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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. ("VECTREN SOUTH – ELECTRIC") FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES APPLICABLE THERETO; (3) INCLUSION IN ITS BASE RATES OF COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY PROJECTS; (4) AUTHORITY TO IMPLEMENT A RATE ADJUSTMENT MECHANISM TO TRACK INCREMENTAL CHANGES IN CERTAIN COSTS AND REVENUES RELATING TO ITS GENERATING FACILITIES; (5) AUTHORITY TO IMPLEMENT A RATE ADJUSTMENT MECHANISM TO TRACK INCREMENTAL CHANGES IN NON-FUEL RELATED MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC. ("MISO") CHARGES AND PETITIONER'S TRANSMISSION REVENUE REQUIREMENT; (6) APPROVAL AS AN ALTERNATIVE REGULATORY PLAN PURSUANT TO IND. CODE § 8-1-2.5-6 OF A RETURN ON EQUITY TEST TO BE USED IN LIEU OF THE STATUTORY NET OPERATING INCOME TEST IN ITS FUEL ADJUSTMENT CHARGE PROCEEDINGS; (7) APPROVAL OF REVISED DEPRECIATION ACCRUAL RATES; (8) APPROVAL OF THE CLASSIFICATION OF PETITIONER'S FACILITIES AS TRANSMISSION OR DISTRIBUTION IN ACCORDANCE WITH THE FEDERAL ENERGY REGULATORY COMMISSION'S SEVEN FACTOR TEST; AND (9) APPROVAL OF VARIOUS CHANGES TO ITS TARIFF FOR ELECTRIC SERVICE INCLUDING NEW INTERRUPTIBLE AND ECONOMIC DEVELOPMENT RIDERS.	**CAUSE NO. 43111** **APPROVED:** AUG 1 5 2007

BY THE COMMISSION:
David E. Ziegner, Commissioner
Scott R. Storms, Chief Administrative Law Judge

On September 1, 2006, Southern Indiana Gas Company and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Petitioner," "Company" or "Vectren South-Electric") filed a Petition with the Indiana Utility Regulatory Commission ("Commission") seeking (1) authority to increase its rates and charges for electric utility service; (2) approval of new

schedules of rates and charges applicable thereto; (3) inclusion in its base rates of costs associated with certain previously approved Qualified Pollution Control Property projects; (4) authority to implement a rate adjustment mechanism to track incremental changes in certain costs and revenues relating to its generating facilities; (5) authority to implement a rate adjustment mechanism to track incremental changes in non-fuel related Midwest Independent Transmission System Operator, Inc. ("MISO") charges and transmission revenue requirement; (6) approval as an alternative regulatory plan of a return on equity test to be used in lieu of the statutory net operating income test in its fuel adjustment charge proceedings; (7) approval of revised depreciation accrual rates; (8) approval of the classification of its facilities as transmission or distribution in accordance with the Federal Energy Regulatory Commission's ("FERC") Seven Factor Test; and (9) approval of various changes to its tariff for electric service including new interruptible and economic developments riders. The Petition provided notice of Petitioner's election to proceed under the Commission's rules on Minimum Standard Filing Requirements, 170 IAC 1-5-1 *et. seq.* ("MSFRs").

Petitions to intervene were filed by Mead Johnson and Company and the SIGECO Industrial Group ("Industrial Group"), whose members are Air Liquide Industrial U.S. LP, Countrymark Cooperative, Inc., Marathon Petroleum Company LLC, Mead Johnson and Company, PPG Industries, Inc. ("PPG") and Wal-Mart.[1] These petitions were granted, and these entities (jointly referred to as the "Industrial Group") were made parties to this cause.

Pursuant to the Prehearing Conference on October 16, 2006, the Prehearing Conference Order dated November 1, 2006, and notice of hearing given as provided by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission, a public Evidentiary Hearing in this cause was held on December 11-14, 2006, at which time Petitioner presented its case-in-chief and its witnesses were cross-examined.

Pursuant to Ind. Code § 8-1-2-61(b), a public field hearing was held on January 8, 2007 in the City of Evansville, the largest municipality in Petitioner's service area. At the field hearing, members of the public were afforded the opportunity to make statements to the Commission regarding the proposed rate increase.

On February 27, 2007, the Indiana Office of Utility Consumer Counselor ("OUCC") and the Industrial Group filed the prepared testimony and exhibits constituting their respective cases-in-chief. On March 12, 2007, the Industrial Group filed cross-answering testimony and exhibits responding to the OUCC's prefiled evidence. On March 22, 2007, Petitioner filed its rebuttal testimony and exhibits. Petitioner filed supplemental direct testimony on April 2, 2007 regarding the in-service date and actual cost of the Culley Unit 3 fabric filter project.

On April 17, 2007, the Petitioner filed a Stipulation and Settlement Agreement with PPG (the "PPG Settlement") resolving issues between these parties in this cause and proposing approval of a Special Contract For Electric Service between them ("PPG Agreement"). On April 18, 2007, Petitioner filed a motion to protect certain terms of the PPG Agreement and a PPG affidavit from disclosure. The motion was granted on a preliminary basis by a Docket Entry dated April 20, 2007.

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[1] The Industrial Group's petition to intervene was amended on January 11, 2007 to include Mead Johnson and Company as a member and on March 12, 2007 to include Air Liquide Industrial U.S. LP.

On April 20, 2007, Petitioner, the OUCC and Industrial Group filed a Stipulation and Settlement Agreement ("Settlement" or "Settlement Agreement") containing a proposed resolution of the issues in this proceeding. A copy of the Settlement Agreement is attached hereto as *Exhibit 1* and incorporated herein by reference. On April 25, 2007, Petitioner and the OUCC prefiled supplemental testimony and exhibits in support of the Settlement and Petitioner filed supplemental testimony and exhibits in support of the PPG Agreement. An amendment to the Settlement Agreement which reflected two minor corrections was filed on May 1, 2007.

A hearing on the Settlement was held on May 3, 2007. At that time, the supplemental testimony and exhibits of Petitioner and the OUCC in support of the Settlement were admitted and witnesses for Petitioner and the OUCC responded to questions from the bench. The prefiled cases-in-chief of the OUCC and Industrial Group, Industrial Group's cross-answering testimony, Petitioner's prefiled rebuttal evidence and Petitioner's supplemental direct testimony on the fabric filter project were also admitted for the purpose of providing further evidentiary support for the reasonableness of the Settlement.

Having considered the evidence and being duly advised, the Commission now finds:

1. **Notice and Jurisdiction.** Due, legal and timely notice of the filing of the Petition in this cause was given and published by Petitioner as required by law. Proper and timely notice was given by Petitioner to its customers summarizing the nature and extent of the proposed changes in its rates and charges for electric service. Due, legal and timely notice of the Prehearing Conference, Public Field Hearing and Evidentiary Hearings were given and published as required by law. Petitioner is a public utility as defined in Ind. Code § 8-1-2-1(a) and is subject to the jurisdiction of the Commission in the manner and to the extent provided by the laws of the State of Indiana. This Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

2. **Petitioner's Characteristics.** Petitioner provides electric utility service to approximately 140,000 customers in six (6) counties in southwestern Indiana. Petitioner renders such electric utility service by means of utility plant, property, equipment and related facilities owned, leased, operated, managed and controlled by it which are used and useful for the convenience of the public in the production, treatment, transmission, distribution and sale of electricity.

3. **Existing Rates.** Petitioner's existing basic rates and charges for electric utility service were established pursuant to the Commission's Order dated June 21, 1995 in Cause No. 39871.

4. **Test Year and Rate Base Cutoff.** As provided in the Prehearing Conference Order, the test year to be used for determining Petitioner's actual and pro forma operating revenues, expenses and operating income under present and proposed rates is the twelve months ended March 31, 2006. The financial data for this test year, when adjusted for fixed, known and measurable changes as provided in the Prehearing Conference Order, is a proper basis for fixing new rates for Petitioner and testing the effect thereof. In its petition, the Company stated that it would update its rate base at the initial Evidentiary Hearing. Petitioner also identified its Culley Unit 3 fabric filter project as a major project as defined in 170 IAC 1-5-1(n) that will be in service before the final Evidentiary Hearing and that it proposed to include this project in its rate base pursuant to 170 IAC 1-5-5(3)(B).

5. **Evidence of the Parties.**

A. Petitioner's Case-In-Chief. Jerome A. Benkert, Jr., Petitioner's Executive Vice President and Chief Financial Officer, provided an overview of Petitioner's rate request which included an increase in annual customer bills of $76.7 million or 18.6% comprised of a base rate increase of $135.5 million offset by (a) the rolling into base rates of $45.1 million of pollution control, demand side management ("DSM") and purchased power costs currently included in tracking mechanisms and (b) Petitioner's proposed customer bill credit for $13.7 million in margins from short term wholesale contracts with municipal customers. Mr. Benkert discussed the changes witnessed by Petitioner since its last rate case which include deregulation and reregulation of some electricity markets, the creation of regional transmission organizations, the bankruptcy of some energy generators, initiation of environmental enforcement actions against electric utilities by the U.S. Environmental Protection Agency ("US EPA"), increasing environmental restrictions, increasing pressure on credit ratings and shrinking capacity margins. Mr. Benkert explained that in response to these conditions Petitioner has transitioned to short term arrangements with its municipal customers, invested significant amounts in new generation, emission controls and transmission upgrades, settled a New Source Review lawsuit with US EPA, and transferred functional control of its transmission system to MISO. According to Mr. Benkert, Petitioner faces a continuing need to make large capital expenditures, including for new baseload generation. He said it was imperative that Petitioner be positioned to recover costs, earn solid returns, and provide the capital and debt markets with confidence in its ability to support this level of increased investment.

Mr. Benkert described the Company as a very small electric utility with coal-fired generation having below average rates and competing for capital with larger peer companies. Mr. Benkert listed the credit quality strengths and weaknesses of Petitioner as identified by the credit ratings agencies. He said Petitioner's goal is to raise its ratings, currently Baa1 with Moody's and A- with Standard & Poor's, to the A category. He quantified Petitioner's current capital expenditure projection for the period of 2006 through 2010 at $775 million, over half of which will be supported by external debt and equity financings.

Mr. Benkert also discussed the benefits that have been achieved from the 2000 merger of Indiana Energy and SIGCORP to form Vectren, Petitioner's incentive compensation program, its Asset Management Transformation ("AMT") project (a multi-year internal effort to optimize the efficiency of field work processes and asset utilization) and the return on equity ("ROE") test that Petitioner proposed be used in its fuel adjustment charge ("FAC") proceedings in lieu of the statutory net operating income ("NOI") test. The proposed ROE test would apply the earnings test by comparing Petitioner's actual ROE to its allowed ROE, adjusted upward by 125 basis points to accommodate potential incentive returns for certain projects and the sharing of wholesale margins.

Ms. Susan Hardwick, Vice President, Controller and Assistant Treasurer, testified regarding Petitioner's revenue requirement. She discussed each of the revenue and expense adjustments made to the test year financial results. She determined that a revenue increase of $90,409,801 (net of tracker roll-ins) was necessary to provide an 8.08% return (as determined by Petitioner's Witness Goocher) on Petitioner's net original cost rate base as of March 31, 2006 adjusted for transmission projects scheduled to be placed in service before the first hearing and the Culley Unit 3 fabric filter project. At the hearing on Petitioner's case-in-chief, Ms. Hardwick provided an updated calculation of Petitioner's original cost rate base as of October 31, 2006,

adjusted for the fabric filter project, of $1,042,198,971. *Petitioner's Exhibit MSH-6*. At the final hearing, Ms. Hardwick provided supplemental direct testimony on the actual cost of the Culley Unit 3 fabric filter as of February 28, 2007, which was $50,519,592, including allowance for funds used during construction ("AFUDC") and overheads.

Paul R. Moul, a financial and regulatory consultant, testified regarding Petitioner's cost of equity capital. Mr. Moul expressed the opinion that Petitioner's cost of equity was within a range of 11.75% to 12.25% and recommended that a 12.00% ROE be used for purposes of this case. Mr. Moul's recommendation was based on the results of a discounted cash flow ("DCF") model, a risk premium ("RP") analysis, a capital asset pricing model ("CAPM") and a comparable earnings approach. His studies used a proxy group of ten companies ("Electric Group") that he considered comparable in risk to Petitioner. Mr. Moul said he selected publicly traded electric utility companies that are covered by *Value Line Investment Survey*, are transmission owning members of MISO or former transmission owners which transferred their transmission assets to separate transmission companies, have not recently cut or omitted their dividend, are not subject to a merger announcement and have at least 70% of their assets represented by regulated operations. Mr. Moul asserted that his analysis takes into account Petitioner's wholesale margin tracking and sharing proposal and its environmental tracking mechanisms. Mr. Moul cited Petitioner's high level of industrial and wholesale sales and Petitioner's small size in relation to its needed capital expenditures as specific risk issues affecting Petitioner's required rate of return.

Robert L. Goocher, Vice President and Treasurer, testified regarding Petitioner's capital structure and cost of capital. Using the capital structure as of March 31, 2006, the weighted cost of long term debt, the cost of equity recommended by Mr. Moul and the other components of the ratemaking capital structure (customer deposits, cost free capital and investment tax credits), Mr. Goocher computed a weighted cost of capital of 8.08%.

William S. Doty, Petitioner's President, testified regarding previously authorized MISO cost deferrals to be recovered in this case, Petitioner's proposed MISO Cost Recovery Adjustment ("MCRA"), transmission system staffing, federal reliability initiatives, Petitioner's plan to deal with its aging workforce, training and safety programs, the AMT project, the customer contact center, meter reading and billing costs, customer safety education efforts and utility plant in service (including the recent completion of transmission and substation projects that will improve reliability and import capabilities). He stated the MCRA would track non-fuel MISO charges and credits and should be approved because they are mandated by FERC, variable in amount, variable as to timing and substantial in amount. Therefore, according to Mr. Doty, the criteria applied by the Commission in *PSI Energy, Inc.*, Cause No. 42359, p. 120 (*Ind. Util. Reg. Comm'n*, May 18, 2004) for determining whether to approve MISO cost tracking are consistent with the request in this matter.

Eric J. Schach, Vice President of Energy Delivery, testified about Petitioner's electric service reliability enhancement initiatives. He said these efforts are preventative and proactive in nature and include inspecting, repairing and maintaining substation, underground and overhead facilities and a line clearance program. He described the staffing increases and other costs relating to these activities. He also said that the Petitioner plans to complete a comprehensive long range master planning study of its distribution system and an electrical system protective device coordination study.

Ronald G. Jochum, Vice President-Power Supply, testified regarding how Petitioner's wholesale transactions with municipal customers have changed, since its last rate case, from long term contracts to short term arrangements. Mr. Jocum further indicated that these short term arrangements are likely to end soon because of the customers' interest (especially Indiana Municipal Power Agency) in alternative suppliers, and Petitioner's desire to use this capacity to serve increasing retail demands. Mr. Jochum also testified that the Petitioner proposed that all of its generation be treated as jurisdictional and that 100% of the margins from existing municipal contracts or municipal contracts for the renewal of which offers were then outstanding be credited in Petitioner's proposed Generation Cost and Revenue Adjustment ("GCRA").

With respect to other future municipal transactions (which Mr. Jochum said were unlikely and at best would be short-term opportunity sales) and non-firm wholesale sales (which Mr. Jochum said had declined and would continue to decline from test year levels), Petitioner proposed a sharing mechanism. Under Petitioner's proposal, a $10.5 million credit ("Non-Firm Credit") would be used in setting base rates. This amount represents projected results for the 12 months ended March 31, 2007. Margins during each 12 month period above or below the Non-Firm Credit would be shared between Petitioner and the customers on a 50/50 basis via the GCRA. Mr. Jochum said this approach would protect customers and shareholders from the swings in wholesale margins that will occur in the next several years because of factors such as the retirement of Culley Unit 1, an exceptionally low level of outages during the test year, future outages required for installing environmental controls and the effect of such controls on maintenance requirements and net generation capability. Mr. Jochum testified that wholesale margins will also be affected by fuel prices, fuel availability, market volatility, competitive cost pressure due to Petitioner's small size, and the cost of emission allowances associated with wholesale sales (which are credited to or "bought from" customers at market prices pursuant to settlement agreements relating to Petitioner's environmental projects). Mr. Jochum commented that the uncertainty in wholesale sales during certain periods will be aggravated by transmission constraints on Petitioner's ability to export power. He expressed the opinion that unpredictable fluctuations in financial results attributable to wholesale sales would not serve the interests of the customers or the company, especially when financial stability was needed for major capital improvement and maintenance projects.

Mr. Jochum also discussed Petitioner's staffing, maintenance activities and expenses in the power supply area. He explained the basis for Petitioner's request that chemical costs relating to the operation of environmental equipment and purchased power demand costs be tracked in the GCRA. Mr. Jochum also discussed Petitioner's retirement of Culley Unit 1 and the cost of its NO_x emission reduction projects and the Culley Unit 3 fabric filter. He also identified a demolition contractor's cost estimate of $9.5 million for the demolition of Petitioner's Ohio River Station, including asbestos removal, superstructure dismantlement, building demolition, backfilling and debris disposal.

Michael W. Chambliss, Manager of Energy Delivery Operations, described Petitioner's transmission system, Petitioner's transfer of control over the system to MISO, and Petitioner's near-term and longer-term strategy to deal with transmission constraints and reliability standards.

Mr. Chambliss also testified about Petitioner's study to classify its facilities as transmission or distribution under the Uniform System of Accounts using the FERC Seven-Factor Test.

John P. Kelly, an asset valuation specialist with Concentric Energy Advisors, testified regarding a valuation study he performed of Petitioner's electric utility properties. In his opinion, the replacement cost new less depreciation value of these assets is about $1.987 billion. To make sure the effect of technological change was fully reflected, he made a further downward adjustment using a factor of 2.25% per year from the date of installation as recommended by Mr. Moul, resulting in an adjusted replacement cost less depreciation value of $1.763 billion.

Paul M. Normand and James H. Aikman with Management Consulting, Inc. testified regarding the depreciation study they performed for Petitioner. The study was based on the straight line method, broad group procedure and remaining life technique applied to plant balances as of December 31, 2005. Mr. Normand stated this depreciation model was consistent with Petitioner's last depreciation study which was approved in Cause Nos. 39871 and 40078 (*Ind. Util. Reg. Comm'n,* June 21, 1995). Mr. Normand discussed their physical inspection of Petitioner's property, the historical data and other information used in the study and the Simulated Plant Record life analysis used for the mass accounts. Mr. Aikman testified about the production plant analysis that used a life span forecast, interim retirement ratios and estimates of cost of removal (including the Ohio River Station demolition cost estimate) and salvage values. The existing and recommended depreciation accrual rates resulting from the study summarized by major functional group were:

Plant Category	**Existing Accrual Rate (%)**	**Proposed Accrual Rate (%)**
Total Steam Production	4.03	3.81
Other Production	4.02	3.45
Transmission	2.68	2.02
Distribution	3.38	2.98
General	3.17	4.18
Total Electric Plant	3.76	3.46
Common	4.18	2.95

Ronald B. Keeping, Director of Economic Development and Market Research, testified about Petitioner's role in promoting economic development in southwestern Indiana and its proposed Economic Development ("ED") and Area Development ("AD") Riders. Mr. Keeping described how the Company and its customers benefit from economic development. He said the ED Rider would provide a discount on the demand charge otherwise applicable under Rate LP or Rate HLP, the size of which would depend on the character of the load being added and the character of the customer's economic development project, including the number of jobs created. He said the AD Rider would encourage a customer to make investments in specific parts of Petitioner's service area by providing a discount on the Rate LP or Rate HLP demand charge and is directed to encouraging redevelopment of existing large, unused industrial buildings, brownfield areas and designated economic development zones.

William S. Seelye, a consultant with Prime Group, LLC, testified regarding the various categories of MISO-related costs which he identified as: (1) non-fuel charges pursuant to FERC-approved rate schedules; (2) fuel costs relating to participation in MISO's Day 2 energy market under which MISO directs the dispatch of generating units; and (3) transmission costs included in MISO's FERC-approved Attachment O formula rate applicable to loads that sink in

Petitioner's control area. Mr. Seelye explained how Petitioner proposed to use the MCRA to recover and credit incremental changes from base rate levels in non-fuel and transmission costs. He testified that (a) non-fuel costs (including Section 26 network reliability upgrade charges pursuant to the MISO Transmission and Expansion Plan ("MTEP")) would be tracked in the MISO Charges Component of the MCRA and (b) the MISO Attachment O transmission revenue requirement would be tracked in the MISO Transmission Component of the MCRA. Mr. Seelye said the MCRA is largely modeled on Duke Energy Indiana's IURC-approved Standard Contract Rider No. 68. He also sponsored proposed schedules to be used in MCRA filings. Mr. Seelye said the fuel costs related to the MISO Day 2 energy market would be recovered in Petitioner's FAC as provided in the Commission's Order in Cause No. 42685 dated June 1, 2005.

Kerry A. Heid, a rate consultant, performed a cost of service study for Petitioner's electric utility business and allocated the revenue requirement to the various rate schedules. Mr. Heid determined the rate of return on the rate base allocated to each rate schedule and the corresponding subsidies paid or received, as compared to equalized rates of return. He also calculated the subsidy levels at Petitioner's proposed rates. Mr. Heid explained how the proposed rates for each rate schedule were determined and identified increases that would be experienced by customers in each class.

William R. Hopkins, a utility consultant with Concentric Energy Advisors, testified on Petitioner's proposed rate design. He described the proposed changes to the terms, language and rates in the rate schedules. As discussed by Mr. Hopkins, these changes include redesignating the Service Charge as the Customer Facilities Charge; introducing an additional kWh block-step in Rate EH, Home Heating Service; separating Rate GS, General Service, into two separate schedules for demand metered and non-demand metered customers; and adding a minimum bill and minimum contract term to new and renewing customers under Rate LP, Large Power. Mr. Hopkins also described two new proposed interruptible service riders that would offer more cost savings options to customers with on-site generating and/or significant load control capabilities. According to Mr. Hopkins, Petitioner's proposed rates reduced subsidy levels by 25% based on past Commission directives. Mr. Hopkins explained how the cost of service study was used to develop the charges for each rate schedule. He said the Customer Facilities Charges represent approximately 50% of each rate schedule's customer related costs and that an attempt was made to limit the maximum bill impacts to twice the overall rate increase for each rate schedule. He also sponsored an exhibit showing the impact of the proposed rates on typical bills for each rate schedule.

Jerrold L. Ulrey, Vice President, Regulatory Affairs and Fuels, sponsored Petitioner's proposed Electric Tariff and described how it differed from the existing tariff. Mr. Ulrey identified the costs and revenues that would be included in the GCRA as non-firm wholesale margins, municipal wholesale margins, purchased power non-fuel costs, environmental chemical costs, emission allowance credits net of costs, direct load control billing credits and interruptible sales billing credits. He also quantified the pro forma amount of each such item proposed for inclusion in base rates. Mr. Ulrey explained how the GCRA rates would be calculated and why, in his opinion, a tracking mechanism was appropriate for the items to be reflected in the GCRA. Mr. Ulrey also testified about the regulatory filing process that would be used for the GCRA and MCRA and sponsored proposed schedules to be used in GCRA filings.

Mr. Ulrey addressed a few changes Petitioner proposed to make to the General Terms and Conditions section of its Tariff. Finally, he discussed the reconciliation in the GCRA and

MCRA of the actual balances for certain deferred DSM, environmental and MISO Day 1[2] costs as of the anticipated effective date of the rates approved in this proceeding.

B. <u>OUCC's Case-In-Chief.</u> Joan M. Soller, Director of the OUCC's Electricity Division, evaluated Petitioner's proposed energy delivery programs, GCRA, MCRA and ROE test. She acknowledged the significant impact on Petitioner of changes in the industry and in Petitioner's specific situation since its last rate case.

Ms. Soller testified that the OUCC encouraged the Petitioner to update and improve its maintenance practices by focusing on preventative maintenance but favored a more gradual implementation of the programs after completion of the planning studies discussed by Petitioner's Witness Schach. The OUCC suggested that the Company file periodic progress reports utilizing service quality benchmarks to measure improvements, and hold informal meetings with the Commission and the OUCC to discuss the results. Ms. Soller explained the reasons for the OUCC's position regarding the Petitioner's proposed adjustment for enhanced maintenance programs. In the OUCC's opinion, the scope and resource allocations of some programs should be reduced; that there was a lack of, or inconsistency in, support for certain programs; maintenance schedules should be extended in some cases; certain internal labor expenses should be excluded as duplicative of other adjustments; and some programs would result in offsetting revenue increases. Ms. Soller also indicated that she believed that only three additional line specialist apprentices should be included in the pro forma expense level, rather than ten as proposed by Petitioner.

Ms. Soller said the OUCC encourages the Petitioner to continue its active participation in transmission system modeling and planning efforts with the MISO. She noted the steady decrease in transmission loading relief activity since Petitioner transferred functional control of its transmission system to MISO. Ms. Soller testified the AMT project appeared to be well planned and consistent with industry recommendations. Ms. Soller stated that the OUCC expected the operational savings to be greater than projected by Petitioner and thought a rate review of savings due to increased efficiencies would be appropriate in five years.

Ms. Soller stated that the OUCC generally did not oppose the GCRA, pointing out that six of its components have been tracked by other Indiana utilities. However, the OUCC disagreed with the inclusion of environmental chemical expense in this tracker and contended that the remaining elements should be separated between DSM and reliability. Ms. Soller also proposed that 90% of off-system sales margins above $10.5 million per year should be credited to customers, as an alternative to 50/50 sharing of the differential from the Non-Firm Credit of $10.5 million proposed by Petitioner.

Ms. Soller testified the OUCC generally supports the creation of the MCRA but contended the MISO Transmission Component should not be implemented in the tracker at this time because it deals with normal industry operations. She stated only Section 26 charges for projects approved under the MTEP and allocated to Petitioner pursuant to the Reliability and Economic Cost Benefit allocation process should be considered for tracking. Ms. Soller also believed further clarification and discussion among stakeholders regarding cost recovery and

[2] The first stage of MISO's operations as the independent regional transmission organization with functional control over the transmission systems in its footprint is commonly referred to as MISO Day 1.

potential rate impacts was advisable. She suggested that Petitioner could seek to defer recovery of these amounts until a cost recovery mechanism is agreed upon in a separate proceeding.

Ms. Soller stated the OUCC did not support Petitioner's proposed ROE test at this time. She said the Commission did not accept an ROE test for gas cost adjustment purposes in Cause No. 43046 and no change in the law or facts justified departure from that recent Commission decision.

Wes R. Blakley, Senior Utility Analyst for the OUCC, also testified on the GCRA and MCRA. He described the GCRA as a multi-expense tracker in contrast to the single-expense trackers now used by Indiana utilities for purchased power, environmental costs, DSM, reliability and fuel. He recommended that environmental chemical expense relating to completed projects rolled into rate base not be tracked in the GCRA because that may disproportionately address costs trending upward without tracking other costs trending downward or revenues that increase. Mr. Blakley also proposed that the direct-load control billing credits be recovered through a separate DSM tracker and the remaining components through a reliability tracker.

Mr. Blakley provided a comparison of the MISO Charge Component of Petitioner's proposed MCRA and Duke Energy Indiana's RTO tracker, noting that Duke does not include MISO Schedule 24 and 26 Charges (balancing authority expenses and transmission capital investment). He testified that Petitioner has agreed to recover uninstructed deviation amounts in the FAC, rather than the MCRA. He also said any tracking mechanisms approved in this cause should be filed no more frequently than semi-annually. He expressed the OUCC's interest in working collaboratively with Petitioner on the workpaper templates and schedules to be used in tracker adjustment filings.

J. Randall Woolridge, a finance professor at Pennsylvania State University, testified on behalf of the OUCC regarding the Petitioner's cost of capital. He used Petitioner's proposed capital structure and debt cost rates and a cost of common equity of 9.25% to calculate a weighted cost of capital of 6.77%. He said the 9.25% equity cost rate was based on his application of a DCF model. He also performed a CAPM study resulting in a rate of 8.7% but gave that result less weight because he believed risk premium studies were less reliable. Dr. Woolridge accepted and used Mr. Moul's ten-member Electric Group in both his DCF model and CAPM study. However, Dr. Woolridge took issue with some of Mr. Moul's techniques and approaches.

Michael J. Ileo, a consultant with Technical Associates, Inc., testified on behalf of the OUCC regarding the Petitioner's depreciation study. Dr. Ileo recommended that Petitioner's proposed depreciation rates for the various plant accounts be accepted when they were equal to or lower than the current depreciation rate or where no depreciation rate currently exists. However, he indicated that the Company's proposed rates be rejected when they were higher than the current depreciation rate, so as to leave the current depreciation rate in place. He also asserted that the depreciation rate for the Culley Unit 3 fabric filter should be 5.83% pursuant to the settlement in Cause No. 42861, rather than 6.28% as proposed by Petitioner's Witnesses Normand and Aikman. Dr. Ileo contended that his recommendations were justified because inconsistencies in data or lack of data did not permit the proposed depreciation rates to be tested for appropriateness. He also recommended that Petitioner undertake efforts to make its continuing property records capable of supporting depreciation proposals by compiling data from

engineering job orders on the vintage age characteristics, removal costs and salvage values of transmission, distribution and general plant. He said this effort could be limited to random sampling. While Dr. Ileo said there were no significant data issues with respect to production plant, he disagreed with the procedure used by Mr. Aikman to determine deactivation dates for the generating stations.

Thomas S. Catlin, a consultant with Exeter Associates, Inc., testified on behalf of the OUCC regarding the Petitioner's revenue requirement. He calculated a revenue deficiency of $51.4 million using a rate of return of 6.77% (which was equal to Dr. Woolridge's recommended cost of capital rate) and the OUCC's rate base and accounting adjustments. Mr. Catlin used the updated original cost rate base sponsored by Petitioner's Witness Hardwick at the initial hearing. He also accepted Petitioner's proposed revenue adjustments. There were differences between Petitioner's and the OUCC's adjustments for the following expenses: fuel handling, restricted stock and stock options, incentive plan, labor, payroll taxes, aging workforce, maintenance programs (reflecting Ms. Soller's testimony), MISO Day 2,[3] deferred MISO Day 2, deferred MISO Day 1, environmental chemicals, catalyst, substation inspection and maintenance, line clearing, overhead facilities, uncollectibles, meter reading, advertising, property and risk insurance, injuries and damages, outside services, the Vectren Utility Holdings, Inc. ("VUHI") asset charge, and depreciation. After giving effect to tax effects, Mr. Catlin's operating expense adjustments were $11,103,771 less than Petitioner's. *Public's Ex. 6, Sch. TSC-31.*

Richard A. Galligan, a consultant with Exeter Associates, Inc., testified on behalf of the OUCC on the cost of service study, revenue allocations and rate design. Mr. Galligan opposed Petitioner Witness Heid's allocation of generation plant investment and related costs based on each class' relative share of the four highest system peak demands during the test year, *i.e.*, the 4-Coincident Peak method ("4CP method"). Mr. Galligan contended it is incorrect to treat Petitioner's total generation plant costs as if they were caused by peak demands because a portion relates to sustained energy demands. Mr. Galligan supported use of the Peak and Average method ("P&A method") under which 61% of Petitioner's generation plant costs (the percentage Mr. Galligan said was equal to Petitioner's system load factor) would be allocated to the rate classes based on average demands and the rest would be allocated based on peak demands.

Mr. Galligan also disagreed with Mr. Heid's allocation to the rate classes of (a) primary distribution facilities based on the 4CP method and the sum of each customer's non-CP demand; (b) secondary distribution facilities entirely on the sum of each customer's non-CP demand; and (c) transformers on the basis of the sum of each customer's non-CP demand and the number of customers. Mr. Galligan asserted that a portion of this plant should be allocated based on each class' average demand. Therefore, Mr. Galligan advocated use of the P&A method to allocate these costs and showed how this would change the cost of service study.

Mr. Galligan developed his proposed class revenue increase spread by reducing the class subsidies (provided or received) by 25% resulting from a revised cost of service study reallocating generation plant costs based on the P&A method. He stated he did not include his reallocation of primary distribution plant, secondary distribution plant and transformers for this purpose because the allocation of fixed costs associated with distribution facilities is

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[3] The commencement of MISO's day ahead and real time energy markets using security constrained economic dispatch and financial transmission rights is commonly referred to as MISO Day 2.

controversial, transmission level customers are unaffected and index returns under both studies have only small differences and move in the same direction.

Mr. Galligan also proposed limiting the increase in the Customer Facilities Charge for Rate A Residential Service to $5.50 (rather than $7.50 as proposed by Petitioner) and that the energy charge increase to the first block and the tail block of Rate A be increased by the same dollar amount.

C. **Industrial Group's Direct and Cross-Answering Testimony.** The Industrial Group presented the testimony of Michael Gorman of Brubaker & Associates, Inc. regarding the rate of return. Mr. Gorman recommended that the Commission accept a return on equity of 9.8% based on his analysis of Petitioner's cost of common equity using a DCF model, a risk premium model and the CAPM. Mr. Gorman also recommended that return on equity be reduced by 30 basis points if the Commission adopted the new trackers Petitioner proposed in the proceeding. Mr. Gorman used the same Electric Group as Mr. Moul except he eliminated Duke Energy because of the effect of the Cinergy merger on its earnings outlook. Mr. Gorman took issue with some of Mr. Moul's techniques. Mr. Gorman also expressed opinions on fair value ratemaking, assessed Petitioner's risk factors and opposed Petitioner's proposed ROE test.

Nicholas Phillips, Jr., of Brubaker & Associates, Inc. testified on behalf of the Industrial Group on cost allocation and rate design. Mr. Phillips discussed cost of service and rate design principles and the purpose of a cost of service study. Mr. Phillips supported use of the 4CP method for allocating production and transmission investment to customer classes. According to Mr. Phillips, the Petitioner's allocation of transmission and subtransmission plant on the basis of twelve coincident peaks ("12CP method") was a departure from the findings in the last rate order. He also contended FERC's use of the 12CP method for wholesale transmission ratemaking does not require this Commission to use that method for retail rates. Mr. Phillips disagreed with Mr. Heid's failure to use a minimum system technique to classify distribution system costs as customer related. He also stated a preferred method of allocating the rate increase to rate classes would be to reduce subsidies by 50% (rather than 25% as proposed by Petitioner) in order to move rates closer to cost of service and provide more accurate price signals. He also stated that any reduction in Petitioner's proposed increase be used to lower energy charges.

As a policy matter, Mr. Phillips recommended that approval of additional tracking mechanisms be kept to a minimum. He opposed the GCRA, stating that is was complex and unnecessary. Mr. Phillips proposed an alternative sharing approach for non-firm wholesale margins in excess of the base rate level. Mr. Phillips also made a number of suggestions for changes to the MCRA, including elimination of any incentive return in excess of the rate of return found appropriate in this proceeding, use of the 4CP method to allocate transmission costs and use of profits on sales into MISO to offset MISO costs. He also commented on Petitioner's proposed interruptible service riders, calling them a step in the right direction.

Mr. Phillips submitted cross-answering testimony responding to Mr. Galligan's proposal on the P&A method. He said this method was rejected in Petitioner's last rate case and is inconsistent with a subsequent order by the Commission regarding the allocation of pollution control investment. Mr. Phillips asserted the P&A method over-allocates costs to high load factor and off peak customers. Mr. Phillips advocated treating all production investment as demand related. He also disagreed with Mr. Galligan's proposed allocation of distribution

facilities in part on annual energy usage, stating this was inconsistent with the NARUC *Electric Cost Allocation Manual.*

D. <u>Petitioner's Rebuttal</u>. In his rebuttal testimony Mr. Benkert discussed the importance of the establishment of a reasonable ROE in this cause to enable the Petitioner to attract the funds necessary to finance the significant capital expenditures necessary over the next several years. These expenditures include environmental projects, costs associated with additional clean coal-fired generation, and expenditures for transmission system upgrades. Mr. Benkert also discussed the authorized ROEs for the members of the Electric Group, and indicated that since 2002, most ROEs for this group have fallen in the range of 10.75% to 11%. Mr. Benkert also noted the ROE of 10.50% authorized for Duke Energy Indiana in 2004 and contended that the Company's circumstances were comparable to Petitioner's with respect to tracking mechanisms, future financing requirements, coal generation risk, and other factors cited by the Commission in making its ROE finding. Mr. Benkert also stated that interest rates then and now are quite comparable. Mr. Benkert testified that the Petitioner's small size compared to Duke and the Electric Group companies is a separate significant risk factor in the eyes of investors. According to Mr. Benkert, consideration should also be given to Petitioner's risks associated with large customers, and escalating costs that are not tracked and the FAC earnings test which does not apply to utilities in other states.

Mr. Benkert also defended Petitioner's proposed ROE test as superior to the static NOI test because it accommodates Petitioner's future capital requirements while still operating as a safeguard against unintended profits. Mr. Benkert pointed out that after an order is issued in this matter the Petitioner's FAC earnings bank will be reset based on the last five years which will cause Petitioner to lose the ability to use the accumulated under earnings since its last rate case as an offset against future excess earnings. Mr. Benkert also expressed the opinion that the concerns of the Commission in its Order in Cause No. 42943 which rejected an ROE test for purposes of Petitioner's GCA filings have now been addressed. He also discussed other possible alternatives for modifying the NOI test to accommodate Petitioner's anticipated investments.

Ms. Hardwick submitted rebuttal testimony on the revenue requirement issues. She addressed each accounting adjustment of the OUCC that differed from Petitioner's case-in-chief. As a result of changes reflected in her rebuttal exhibits, Petitioner's proposed annual revenue increase was reduced from \$90.4 million to \$80.4 million (producing NOI of \$83,079,998). She also disputed Dr. Ileo's testimony regarding the condition of Petitioner's books and records. Ms. Hardwick testified the adequacy of Petitioner's records was shown by its annual unqualified audits and timely and accurate regulatory reporting.

Mr. Moul submitted rebuttal testimony, in response to the testimony of Dr. Woolridge and Mr. Gorman, on the cost of equity and disagreed with certain of their opinions and analyses. Mr. Moul said their recommendations were too low by reference to returns expected by investors and granted by regulators. Mr. Moul also stated that due to changes in market conditions since his direct testimony was submitted, a cost of equity capital of 11.75% would now be reasonable for Petitioner.

Mr. Doty rebutted the OUCC's testimony on Petitioner's aging workforce adjustment. Although he opposed some of the OUCC's proposed reductions in the amount of the adjustment, he confirmed Petitioner's agreement to reduce a number of expense items raised by the OUCC. Mr. Doty accepted Mr. Catlin's quantification of ongoing MISO Day 2 costs and updated level

of deferred MISO Day 2 costs. He did, however, dispute Mr. Catlin's quantification of deferred MISO Day 1 costs. Mr. Doty also provided updated information on the hiring of additional employees and opined regarding the need for recovery of the costs of Petitioner's entire proposed safety education program (not just the school component).

Mr. Schach responded to Ms. Soller's position on maintenance program reporting and metrics. He said that Petitioner will agree to proceed more gradually with certain programs, provide periodic progress reports, engage in meetings about the reports, and put performance metrics in place. Mr. Schach also provided updated program cost data which he said resolved inconsistencies in outdated data previously provided to the OUCC. Mr. Schach testified that the Company was agreeable to providing the OUCC and the Commission with periodic reports on the status of the AMT project, but did not see the need for an automatic rate case trigger in five years.

Mr. Jochum testified in rebuttal against the positions of the OUCC and the Industrial Group on alternatives to Petitioner's proposal for non-firm wholesale margin sharing. Mr. Jochum characterized these alternatives as asymmetrical because they guaranteed a base rate reduction of $10.5 million for the Non-Firm Credit, required Petitioner to absorb 100% of any shortfall and would give the customers much of the upside if sales exceed $10.5 million. Mr. Jochum testified traditional ratemaking would be better for Petitioner than the sharing alternatives presented by the OUCC and the Industrial Group. Mr. Jochum responded to the OUCC's position on fuel handling expense (agreeing to eliminate the adjustment) and the aging power supply workforce (accepting the OUCC's position with modifications). Mr. Jochum disputed the OUCC's position that environmental chemicals and catalyst expense should be excluded from the GCRA, but agreed to a reduction in the base rate level of catalyst expense. He also provided updated information on wholesale service to Huntingburg and the closure of Culley Unit 1.

Mr. Chambliss responded to Ms. Soller's testimony about transmission expansion by describing needed near term system improvements in southwestern Indiana. He also explained MISO's process for approval of transmission projects and the opportunity of stakeholders like the Commission and OUCC to have input therein. He also discussed Petitioner's scrutiny of low voltage projects not subject to MISO approval and its willingness to make its analyses available to show approved projects are essential and cost effective.

Mr. Aikman submitted rebuttal to Dr. Ileo's testimony on the depreciation study. He testified there were no data problems and that Petitioner's records contain all of the necessary detail to conduct a full study and reach a conclusion on appropriate depreciation rates. He also defended the generating plant retirement dates and interim retirement ratios used in the study. Mr. Aikman, however, did agree that the correct depreciation rate for the Culley Unit 3 fabric filter was 4.83% as recommended by Dr. Ileo.

Mr. Seelye's rebuttal testimony responded to the evidence of the OUCC and the Industrial Group on transmission investment and MISO cost recovery. In response to Mr. Blakley's testimony, Mr. Seelye testified that the MCRA would include netting of MISO transmission revenues to reduce customer costs. He clarified the allocation to Petitioner of FERC Schedule 26 charges and credits, and Petitioner's proposed treatment of them in the MCRA. Mr. Seelye also addressed the concerns expressed by Ms. Soller that lead her to recommend that the MTC not be implemented in the MCRA at this time. He disagreed with Ms.

Soller's position that the MTC is overly-broad and her suggestion that Petitioner should instead seek deferral authority for MTEP-approved projects pending tracking approval in a separate proceeding. As an alternative, Mr. Seelye said Petitioner would accept limiting transmission costs in the MCRA to Regional Expansion Criteria and Benefit Process ("RECB") charges (whether due to Petitioner's own projects or the allocation to Petitioner of third party RECB projects) and authorization to accrue post-in-service AFUDC and deferred depreciation on non-RECB projects over $5 million that the Commission finds are reasonable. In response to Mr. Phillips' contention that it would be bad policy to approve additional tracking mechanisms, Mr. Seelye discussed his views on the benefits of the MCRA tracking mechanism and asserted the MCRA satisfied approval criteria previously established by the Commission. He also said that Petitioner did not request an incentive return in the MCRA.

Mr. Heid provided rebuttal testimony with respect to the cost of service study. He discussed why Petitioner used the 4CP method for production plant, argued it was supported by the FERC allocation method test and noted that it has been approved in prior rate cases of Petitioner. He also contended Mr. Galligan's P&A method had not been accepted in Indiana and shifted more costs away from residential customers than the method proposed by the OUCC and rejected by the Commission in Petitioner's last electric rate case.

Mr. Heid described how he classified line transformers between the demand function and the customer function and testified that a portion was treated as customer related because the number of transformers is a function of the number of customers. He criticized Mr. Galligan's position that no transformer costs should be treated as customer related and that some transformer costs should be allocated based on energy sales.

Mr. Heid indicated that his allocation of primary and secondary distribution plant based on demand was consistent with Petitioner's prior studies. He also believed that the use of the 12CP method for transmission plant allocations was justified because of recent changes in the nature and use of its transmission system due to open access.

Mr. Hopkins testified on rebuttal that he opposed Mr. Galligan's position on production, line transformer and distribution system plant costs and stated that Mr. Galligan's methods would place an extreme cost burden on Petitioner's most efficient customers and off-peak users. Mr. Hopkins contended that the Petitioner's proposed Customer Facilities Charge was supported by the cost of service study and was comparable to such charges of other Indiana electric utilities.

Mr. Ulrey said Petitioner accepted the OUCC's proposal that separate trackers be created for the reliability and DSM components of generation related costs and revenues. He sponsored proposed tariff sheets and filing schedules for these trackers, called the Demand-Side Management Adjustment ("DSMA") and the Reliability Cost and Revenue Adjustment ("RCRA"). With respect to Mr. Phillips' criticism of trackers, Mr. Ulrey commented on the benefits, including cost reduction pass throughs that could be achieved by the proposed trackers. He also discussed changes to Petitioner's proposed MCRA that were responsive to the testimony of Ms. Soller and Mr. Blakley, including by submitting revised tariff sheets and filing schedules. He also presented a proposed filing process for the RCRA, MCRA and DSMA.

6. <u>The Settlement Agreement.</u> In the Settlement Agreement, the settling parties state that they have devoted significant time to the review of data and the discussion of issues and have succeeded in reaching agreement on all issues in this proceeding. The parties further

state that, with few exceptions, the agreed upon pro forma adjustments to test year results either reflect the testimonial rebuttal position of Petitioner or the testimonial position of the OUCC, and thus are founded upon documented positions that are in the record in this proceeding.

A. **Rate Increase.** The Settlement provides that Petitioner shall be authorized to increase its basic rates and charges (collectively "rates") for electric utility service with the rates being designed to produce base revenues of $479,915,205. The increase provides for additional annual revenues of $67,255,394 or $60,794,647, this lesser amount being net of the expected credit in the first year as municipal contract revenues are passed back to customers. Based on additional revenues of $60,794,647, the overall revenue increase is approximately 15%. The base rate increase reflects the roll-in of certain NO_x and multipollutant control equipment capital and operating costs currently being recovered under Ind. Code 8-1-8.8, as well as the recovery of deferred DSM costs, deferred MISO costs and base amounts of purchase power demand costs. The Settlement rates reflect allocation of the revenue increase among all rate classes based on a Settlement cost of service, including a 25% subsidy reduction.

The agreed-upon rate increase reflects the following original cost rate base, cost of capital and financial results which the parties agree are reasonable for purposes of compromise and settlement:

Rate Base as of October 31, 2006

	($000's)
Utility Plant in Service	$1,783,735
Less: Accumulated Depreciation	812,809
Net Utility Plant	970,926
Materials and Supplies	42,987
DSM Regulatory Asset	29,156
Other Regulatory Assets	650
Total	$1,043,719

Capital Structure as of March 31, 2006

	Amount ($000's)	Weight	Cost	Weighted Cost
Common Equity	$ 549,508	47.05%	10.40%	4.89%
Long Term Debt	451,347	38.65%	6.04%	2.34%
Customer Deposits	5,601	0.48%	5.39%	0.03%
Cost Free Capital	152,477	13.06%	0.00%	0.00%
Post 1970 JDITC	8,920	0.76%	8.43%	0.06%
	$1,167,853			7.32%

Pro Forma Proposed Rates

	($000's)
Revenue	$ 479,915
Fuel and Purchased Power Costs	158,632
Gross Margin	321,283
O&M	131,232
Depreciation	64,274
Income Taxes	34,501
Other Taxes	14,876
Total Operating Expense	244,883
Net Operating Income	$ 76,400

Effective upon implementation of the rates, which shall be set forth in a revised Tariff for Electric Service, I.U.R.C. No. E-12 ("Tariff"), Petitioner's authorized return for purposes of the earnings test component of the FAC (Ind. Code §§ 8-1-2-42(d)(3) and 42.3) shall be $76,400,199 representing a return of approximately 7.32% on an original cost rate base of $1,043,718,562.

The Settlement provides Petitioner's depreciation rates have been adjusted to the asset category-specific depreciation rates consistent with the Petitioner's Rebuttal Testimony in this cause.

B. **Pro Forma Adjustments.** All of the agreed upon pro forma adjustments are set forth in Appendix C of the Settlement Agreement which compares the Settlement adjustments to Petitioner's case-in-chief, the OUCC's case-in-chief and Petitioner's rebuttal. The Settlement explains the differences between the evidence of Petitioner and the OUCC on each disputed adjustment and how each was resolved for purposes of the Settlement. The adjustments about which there was conflicting evidence were resolved as follows:

Fuel Handling Expense. Petitioner agreed to remove the entire pro forma amount.

Ongoing MISO Day 2 Costs. The Settlement accepts the OUCC's proposed reduction in ongoing MISO Day 2 costs.

MISO Day 1 and Day 2 Costs Deferral Amortization. Petitioner proposed recovery of its deferred MISO Day 1 costs using a four (4) year amortization period. The OUCC reduced the pro forma based on a different estimate of the level of authorized deferrals. In the Settlement, the OUCC agreed to Petitioner's pro forma amount. With respect to MISO Day 2 costs, the Settling Parties agreed upon an adjustment based on a four (4) year amortization period as proposed by the OUCC (instead of a 3 year period) and a recent updated cost estimate.[4]

[4] While the OUCC and the Petitioner agreed to a four (4) year amortization period for the recovery of MISO Day 1 and Day 2 Costs, additional amortization periods of five (5) years for Demand Side Management costs; three (3) years for New Source Legal Costs; and three (3) years for Rate Case Expenses remained as proposed by the Petitioner and were unchanged by the Settlement Agreement.

Labor Adjustments. The Settlement accepts Petitioner's pro forma adjustments based on target levels of long-term and short-term incentive compensation (instead of projected 2006 below target results).

Additional Employees. Petitioner originally adjusted for the cost of 36 new employees (unrelated to the aging workforce issue). The Settlement provides for the inclusion of the cost of 11 post-test year positions that were filled as of March 2007, offset by the elimination of 12 Culley Unit 1 employees.

Aging Workforce—Power Supply. Petitioner proposed to hire a number of apprentices in the power supply area to be prepared for retirements in the near future. The OUCC reduced the adjustment to reflect offsetting cost savings and fewer power plant trainers. On rebuttal, Petitioner agreed to the majority of the OUCC's recommended reductions, but proposed to retain one of the three trainers eliminated by the OUCC. In the Settlement, the parties agreed to set the pro forma at $885,351 which is about $24,000 less than Petitioner's rebuttal position.

Aging Workforce—Energy Delivery. Petitioner proposed to hire apprentice line specialists, electricians, engineers and trainers in advance of retirements in its energy delivery skilled workforce. Petitioner also included new employees and programs in its Human Resources and Safety departments to support these initiatives, as well as to generally upgrade the performance in these areas. The OUCC recommended elimination of some internal labor costs, three apprentices, and all of the Human Resources/Safety costs. In rebuttal, Petitioner accepted most of these reductions, but preserved certain Human Resources/Safety costs as necessary to address work requirements. The Settlement accepts Petitioner's position on rebuttal.

Environmental Chemical Expenses/Catalyst Expenses. Petitioner included pro forma adjustments of $2,308,679 for chemicals and $2,540,000 for catalyst used in its pollution control processes. To address volatility associated with these costs, Petitioner also requested a tracking mechanism. The OUCC, relying on 2007 contract data and cost projections, reduced the adjustments to $1,114,752 and $1,863,500, respectively. The OUCC also rejected the tracking proposal. On rebuttal, Petitioner accepted the reduced pro formas but argued that a tracking mechanism should be approved. The Settlement eliminates the tracker and adopts the OUCC's position related to the costs.

Energy Delivery Maintenance Programs. With respect to Substations Inspection Programs; Underground Facilities Maintenance; Line Clearance; and Overhead Facilities Maintenance, the Settlement accepts OUCC Witness Soller's recommendations for a written reporting process, update meetings with the OUCC, progress reviews with reference to certain agreed-to metrics and a more gradual approach to implementation.

Substations Inspection Programs. Petitioner proposed a program that included periodic breaker inspections, painting, infrared scanning and other maintenance activities. The OUCC eliminated the breaker inspections, recommended annual infrared scans instead of semi-annual, and extended the painting cycle from 10 to 15 years. On rebuttal, Petitioner provided further explanation of its breaker inspections, and agreed to the change in frequency related to both infrared scans and painting. After further discussion and some changes to the timing of breaker inspections to comply with recently approved NERC reliability standards, the parties agreed to a pro forma amount of $751,068.

Underground Facilities Maintenance. Petitioner proposed to engage in regularly scheduled inspections of its downtown Evansville underground network given its age and increasing usage. The OUCC agreed with the program but eliminated costs it interpreted to be non-incremental internal labor. In the Settlement, the parties agreed on an amount of $327,162 which reflected elimination of disputed internal labor costs.

Line Clearance. Petitioner proposed adoption of a five year cycle for tree trimming on its distribution and transmission system. The OUCC supported this cycle, but reduced the cost of the activity. On rebuttal, Petitioner supported the original cost estimate. In the Settlement, Petitioner agreed to the OUCC's reduction.

Overhead Facilities Maintenance. Petitioner proposed a multifaceted program to enhance its inspection and maintenance of overhead facilities, including annual pole inspections, transmission tower painting, inspections of pole guys and grounding, ongoing inspections and work to improve circuit reliability, infrared inspections of circuits and switches, review and improvement of animal guards and frequently failing system components, and the addition of 10 line specialists (other than to replace retirees) to reduce reliance on contract labor which will likely be harder to find as the aging workforce issue impacts contractors. The OUCC recommended almost $1.4 million of reductions with additional circuit flyovers and internal labor on several programs, differences in calculation of certain estimates, change in cycle times for infrared inspections, changing the transmission tower painting cycle from 5 to 20 years, and reducing the hiring of 10 new line specialists to three new line specialists. On rebuttal, Petitioner agreed to reduce the pro forma to reflect a move to a 10 year cycle on tower painting, a change from annual circuit inspections to every two years, cost reductions to reflect reductions in internal labor, and a proposed hiring of 6 new linemen instead of 10. In settlement, Petitioner and OUCC carefully reviewed each program and negotiated further adjustments to several programs, and reduced the number of new linemen to be hired to 5. The final pro forma is $2,478,136.

Uncollectible Accounts Expense. Petitioner based its bad debt expense on a five year historic average percent of revenue (0.38%) while the OUCC proposed use of a more recent three year historic average percent of revenue as of March 2006 (0.26%). Petitioner on rebuttal used the historic three year average ended December 2006 (0.31%). In the Settlement, Petitioner agreed to the OUCC's three year average.

Safety Communication Costs. Petitioner proposed both a school based safety education program as well as a mass media approach to customer safety education. The OUCC agreed to the school program, but eliminated the remaining costs, contending that they were primarily marketing costs. Petitioner defended its entire communication proposal on rebuttal. In the Settlement, Petitioner agreed to the OUCC's positions.

Property and Risk Insurance. The Settlement reflects a reduction in this expense due to a reduction in insurance premiums that occurred during the pendency of the case.

Claims Expense. The OUCC reduced Petitioner's claims expense to exclude recovery of an unpaid claim and to reflect use of five year amortization of another large claim instead of Petitioner's proposed three year amortization. On rebuttal, the Petitioner explained that the large unpaid claim had recently been paid and that a three year amortization period made sense, especially in light of the Company's heightened risk due to its recent increase in its

liability insurance deductible (the reduced premium cost having been passed on to customers). The Settlement uses a five year amortization period for large claims resulting in a pro forma of ($833,893).

Customer Service Costs. In response to concerns expressed at the public field hearing and following an extended collaboration between Petitioner and the OUCC, the Settlement provides for the implementation of three new customer service options: (1) the installation in the City of Evansville of a centrally located payment kiosk where, with no fee, customers can deposit cash payments in a programmed machine; (2) new payment sites in Evansville and Mt. Vernon where customers can pay gas bills at locations where water bill payments are currently collected; and (3) dedication of 1-2 new employees who will be trained to meet with customers to discuss complaints, thereby providing customers with the opportunity to engage in face-to-face communication with Petitioner. The cost of these new services, on an allocated basis to Vectren South-Electric, is $93,000 and is reflected in the Settlement.

Asset Charge. The Settlement calculates the asset charge by which a share of the cost of assets owned by VUHI (Petitioner's immediate parent company) and used in common by its utility subsidiaries is allocated to Vectren South-Electric using the agreed-upon 10.4% ROE.

Depreciation. The Settlement states that the rebuttal testimony and settlement discussions, including a review of the data used by Petitioner to support its depreciation study, addressed the OUCC's concerns regarding Petitioner's proposed depreciation rates. Petitioner agreed to the OUCC's recommendation regarding the depreciation rate for the Culley Unit 3 fabric filter.

Income Taxes, IURT Taxes. There are no differences between the parties on these items which have been determined based upon the settlement amounts.

C. ROE Test. The parties have agreed that Petitioner's proposed ROE test will not be adopted as a replacement for the existing NOI test. However, consistent with past treatment, the parties agree that Petitioner's authorized NOI should be adjusted in the future to allow Petitioner to retain its recovery of costs associated with approved Senate Bill 29 projects (Ind. Code §8-1-8.8 *et seq.*), as well as for the agreed-upon NOI adjustment associated with the opportunity to retain a share of non-firm wholesale power margins ("WPM") as described below. The parties have also agreed that within 30 days of an order in this proceeding, the OUCC will invite Petitioner and the Industrial Group, as well as other interested stakeholders, other utilities and the Staff to discuss the relative merits of the NOI test versus an ROE earnings test. The OUCC and/or Petitioner may or may not ultimately file a petition related to the earnings test following these discussions.

D. Generation Cost and Revenue Adjustment Mechanism. The parties have agreed that the GCRA will be renamed the Reliability Cost and Revenue Adjustment ("RCRA") and that changes from the base rate amount of Direct Load Control Billing Credits will be tracked separately under the Demand Side Management Adjustment. The parties further agree that Petitioner's proposal to track changes in chemical and catalyst costs will be withdrawn. Therefore, the RCRA will be used to adjust Petitioner's rates for the following items:

1. Non-Firm Wholesale Power Margins (WPM)

2. Municipal Wholesale Margins

3. Environmental Emission Allowance (EEA) Credits

4. Interruptible Sales billing credits

5. Purchased Power Non-Fuel Costs

Two of these items, Municipal Wholesale Margins and EEA credits, represent pass through of cost reductions to customers. Petitioner will provide 100% of the margins from its Municipal Wholesale contracts to customers (following an order in this case) during the remaining duration of these contracts in 2007 and 2008, including sales to municipal suppliers during this period as described in Mr. Jochum's rebuttal testimony. Petitioner will also credit customers for 100% of the market value of all EEAs it uses to back its WPM sales. The EEA credits reflect use of SO_2 and NO_x allowances, and at the time required for compliance in the future, this adjustment will also reflect the value of mercury allowances.

Petitioner will file the RCRA semi-annually (every 6 months). The first 6 months of estimated credits from municipal wholesale sales and EEA credits will be filed at the same time new rates from this proceeding go into effect. In each new tracker filing, Petitioner will include a forecast of the amount of future RCRA filings. The sharing of WPM results may also provide a credit or a charge to customers depending upon the level of such margins achieved by Petitioner compared to the base rate revenue requirement credit of $10.5 million as described below.

To the extent Petitioner incurs purchased power demand costs different from its base level of costs, those differences will be tracked under the RCRA. Also, to the extent that the Petitioner incurs Interruptible Sales billing credits different from the base level of such billing credits, those differences will be tracked under the RCRA. Currently, Petitioner provides a billing credit to one large interruptible customer.

E. Non-Firm Wholesale Power Margins. In its case-in-chief Petitioner proposed to follow the approved Duke Energy Indiana model and share WPM results 50/50 with customers. Petitioner "embedded" as a credit to its revenue requirement in this case $10.5 million, the pro forma amount of WPM. Under the proposal, Petitioner and customers share equally in results above and below that $10.5 million target. The parties have reached agreement that Petitioner should retain an incentive to maximize WPM results, and that risk and reward in this area should be shared. Therefore, under the Settlement, this 50/50 sharing proposal has been adopted, with the customer share of WPM to flow through the RCRA. The parties recognized that Petitioner's current NOI under earnings bank of ($202 million) will be eliminated upon receipt of an order in this case, thereby potentially reducing Petitioner's opportunity to retain its potential share of WPM proceeds. Thus, the incentive opportunity may be effectively lost and customers could receive both their 50% share of additional WPM proceeds as well as Petitioner's share of WPM proceeds. To address this particular set of circumstances, the parties have agreed that for four years (16 FAC quarters) following the order herein, Petitioner will be allowed up to a $3 million increase to its authorized NOI in each quarter for purposes of calculating the NOI earnings test, but only to the extent that Petitioner's share of WPM proceeds recorded on Petitioner's books have created its over earning status. This incremental amount provides the ability to retain the 50% share WPM proceeds.

F. MISO Cost and Revenue Adjustment. The parties have reached agreement to track changes in the base expense amounts of non-fuel MISO costs, costs associated with MISO Day 1 and Day 2 which are not already recovered via the FAC.

In this case, the Petitioner had also proposed to recover its costs associated with future investments in transmission infrastructure. On rebuttal, Petitioner divided its transmission investment into three distinct categories: (1) existing investment included in retail rate base, (2) RECB investment, and (3) non-RECB MISO reviewed and approved investment. With respect to these 3 categories of investment, the parties have agreed as follows: current investment will remain included in retail rate base. RECB costs will be tracked, and non-RECB costs will not be tracked. RECB costs will be charged to Petitioner under MISO Schedule 26—this will include charges related to Petitioner's own RECB projects as well as its allocation of costs related to other third party RECB projects. Through Schedule 26, Petitioner will receive partial cost recovery for its projects from other transmission owners in the MISO footprint on an allocated basis. Petitioner will be authorized to retain the allocated portion of cost recovery from native load customers as calculated under Schedule 26 as well as the revenues received from other MISO transmission owners under Schedule 26—all such Schedule 26 recoveries shall be treated as non-jurisdictional and outside the earnings test to allow Petitioner to recover its costs. Petitioner's RECB projects will not be included in retail rate base.

Petitioner will also invest in other reliability projects that do not qualify for RECB treatment, but will be MISO approved (non-RECB projects). Petitioner has agreed to withdraw its request to recover costs related to such projects between rate cases under its proposed MISO Transmission Component of the MCRA, and has also dropped its alternative request for post-in service AFUDC and deferred depreciation for such projects.

With respect to ratemaking related to MISO tariff/costs, nothing in the Settlement should be interpreted to prevent Petitioner from pursuing cost recovery or different ratemaking treatment in later proceedings based upon newly adopted statutes or orders issued by the FERC or IURC. In future proceedings regarding MISO tariff/cost recovery, nothing in this Settlement will be interpreted to prevent the parties from taking any position with respect to cost recovery proposals.

A representative level of transmission revenues has been included as revenue credits in the Settlement revenue requirements. The parties have agreed to track actual differences from these base rate levels during the first year after the implementation of new rates in this proceeding. Prior to the end of the first year, the parties will meet to review available data regarding Petitioner's actual transmission revenues. After review and discussion, the parties will present to the Commission a proposal regarding the future tracking of actual differences from the transmission revenues credited in base rates. That proposal will address Petitioner's ability to retain the portion of transmission revenues related to its non-RECB transmission investment not otherwise recovered from retail customers. Absent agreement of the parties, any party may file a tracking proposal and revenues will be deferred until further order of the Commission.

Petitioner will file the MCRA semi-annually (every 6 months). In each new tracker filing, Petitioner will include a forecast of the amount of future MCRA filings.

G. Future Rate Case and Reporting Commitments. The parties agree that Petitioner will file a base rate case no later than December 31, 2012. During this interim period,

Petitioner will provide reports to the OUCC regarding certain system metrics and progress on maintenance programs. The framework related to the timing and contents of such reports is set forth in Appendix D of the Settlement Agreement. The various cost recovery trackers agreed to in the Settlement shall remain in effect until a final order in the next rate case. Should the parties reach mutual agreement to extend the deadline for the next rate case, they will inform the Commission of the decision to extend the filing date and the basis thereof prior to December 31, 2012. When Petitioner files its next base rate case, Petitioner will file two (2) cost of service studies: one using 4CP to allocate all operating costs, and the other will be the same except for using 12CP to allocate jurisdictional transmission costs. Petitioner may recommend use of either approach.

H. Cost of Service/Rate Design. For purposes of settlement only, the parties have agreed to maintain the existing cost of service allocations, including transmission and generation function allocations based on a 4CP methodology, and to reflect a 25% subsidy reduction. The revenue responsibility for each rate schedule has been established based on the Settlement cost of service. The cost of service allocation reflects Petitioner's special contract with PPG Industries which has been filed with the Commission pursuant to a separate Settlement Agreement. To the extent the PPG Settlement is not approved, Petitioner would modify its cost of service study to reflect the implications of continuing to serve PPG at the new base rates.

The Settlement rates and charges are reflected in the Revenue Proof filed with testimony. Except for Residential Rate A, the Settlement revenue increase for each rate schedule was distributed among the rate schedule's Customer Facilities Charge, Demand Charge (where applicable), and Energy Charges rate blocks in the same manner as in Petitioner's case-in-chief, continuing the objective of having the bill impacts to any customer be no more than approximately two times the overall rate schedule increase. For the Residential Rate A, the Customer Facilities Charges was established at $5.50 and the Energy Charge rate blocks were increased from present rates on an equal percentage basis to recover the remaining rate class increase.

I. Tariff. The Settlement Tariff includes a number of changes as proposed by Petitioner in its case-in-chief as well as updated tariff sheets reflecting tariff changes approved by the Commission after the initiation of this rate proceeding. The Settlement identifies the changes in rate schedules, riders, appendices and terms and conditions made by the Settlement Tariff and notes that other minor changes of a housekeeping nature have been made throughout the tariff.

J. Request for Prompt Approval by the Commission. The parties acknowledge that a significant motivation for Petitioner to enter into the Settlement is the expectation that an order will be issued promptly by the Commission authorizing increases in its rates and charges and ask that their request for prompt approval be seriously considered and acted upon.

K. Stipulation Effect, Scope and Approval. The Settlement provides that it is conditioned upon and subject to its acceptance and approval by the Commission in its entirety without any change or condition that is unacceptable to any party. The Settlement shall not constitute an admission or waiver by any party or be used as precedent in any other proceeding or for any other purpose except to the extent provided for herein or to the extent necessary to implement or enforce its terms. The parties stipulate that the evidence submitted in support of the Settlement constitutes substantial evidence sufficient to support the Settlement and provides

an adequate evidentiary basis upon which the Commission can make any findings of fact and conclusions of law necessary for the approval of the Settlement.

L. Evidence of the Parties In Support of the Settlement Agreement.

(i) Petitioner's Evidence. Mr. Benkert testified that the Settlement Agreement resulted from a series of meetings, discussions and information exchanges between the parties over a period of months, including discussions between the OUCC's technical experts and Petitioner's operations personnel on the proposed maintenance programs. Mr. Benkert stated that, after good faith efforts, including scrutiny of the evidence submitted by the various parties and the give and take of settlement negotiations, the parties were able to reach agreement on the Settlement as a reasonable resolution of this proceeding and a means to avoid further litigation.

Mr. Benkert explained that the Settlement provides for rates designed to produce additional annual revenues of $67,255,394. He said that after reducing this amount to reflect the estimated credit for the pass through to customers of municipal margins under existing contracts, the increase is $60,794,647, which represents an overall revenue increase of less than 15%.[5] Mr. Benkert noted that this is a substantial reduction to Petitioner's original request in this proceeding for a rate increase of $90.4 million per year (less municipal contract revenues). He also said the Company's various cost recovery mechanism proposals were reviewed, with some being withdrawn and others modified during negotiations.

Mr. Benkert pointed out that the Settlement Agreement itself provides significant detail related to the agreed-upon revenue and expense adjustments, original cost rate base, and capital structure, all of which are directly grounded in the prefiled evidence of the parties. Mr. Benkert stated that the agreed-upon revenue requirement represents a 7.32% rate of return on the original cost rate base computed using a return on common equity of 10.4%, a rate that is less than the actual and authorized returns of many of Petitioner's industry peers. Mr. Benkert asserted Petitioner agreed to an ROE of 10.4% in a spirit of compromise, to achieve rate relief sooner than would otherwise be the case, and because it is one part of a negotiated package of settlement terms.

Mr. Benkert stated that firm municipal contract sales will be used to reduce customer bills during the duration of the existing contracts, the last of which expires in 2008. He also said 50% sharing of WPM will provide a cost reduction to retail customers if Petitioner can out perform the $10.5 million of annual margin used to reduce the revenue requirement in this case. He provided examples of how the 50/50 sharing of the excess over or shortfall under $10.5 million will occur. He said the examples showed that while Petitioner has an incentive to maximize performance, customers will reap the majority of the margins in either situation.

Mr. Benkert said the majority of Petitioner's original tracking proposals closely resembled those already in place for other Indiana utilities. Mr. Benkert said the tracking of emission allowances will also continue to provide cost reductions to customers, and that the Petitioner will compensate retail customers for the market value of allowances to offset

[5] In response to questions from the bench, Mr. Benkert stated that the $6.46 million offset for municipal margins was an estimate of the credit for the 12 months beginning August 1, 2007 based on the current status and expiration dates of Petitioner's municipal contracts. He said the credit passed back through the RCRA will reflect the actual municipal wholesale margins, which could be different from the estimate.

emissions related to wholesale sales. Finally, Mr. Benkert indicated that the RCRA allows the Company to track changes in purchased power demand costs and interruptible sales credits. Mr. Benkert indicated that he believes that for the foreseeable future the tracker should provide significant net cost reductions to customers. Mr. Benkert further noted that while the Petitioner believes that chemical costs have become increasingly volatile and that replacement of catalyst used to operate SCRs may vary greatly from year to year as layers of catalyst are exhausted, Petitioner agreed in settlement discussions to drop its tracking request for those costs.

Mr. Benkert further testified that the Settlement Agreement recognized that upon receipt of a rate order, Petitioner's historic under earnings bank will disappear, thereby depriving Petitioner of any cushion for retaining its share of incremental WPM achieved.[6] To address this concern the Settlement provides that for the first 16 FAC periods (4 years) subsequent to an order, to the extent that Petitioner's actual NOI exceeds the authorized NOI, and the overage is due to Petitioner's share of WPM proceeds, then in these circumstances up to $3 million of those WPM proceeds will be excluded from the NOI test. This compromise, Mr. Benkert stated, will provide Petitioner with a reasonable opportunity to retain its incentive share of WPM. Mr. Benkert expressed the opinion that having some upside opportunity in this area will retain the intended WPM incentive, send a positive signal to investors. Mr. Benkert sponsored an exhibit demonstrating the application of the earnings test provisions relative to WPM.

Mr. Benkert commented that the Settlement provides for recovery in the MCRA of non-fuel MISO Day 1 and Day 2 costs in essentially the same manner that Duke Energy Indiana currently recovers such costs. Mr. Benkert explained that with respect to the MTEP process, the FERC-supported national policy to increase investment in the transmission grid, the Settlement generally provides for timely recovery of Schedule 26 costs related to RECB whether Petitioner's own planned RECB investment or costs allocated to Petitioner from other transmission investment in the MISO footprint. For its non-RECB projects, Mr. Benkert said Petitioner's request for tracking of post in service AFUDC treatment has been withdrawn.

Mr. Benkert emphasized that apart from addressing Schedule 26, the Settlement affords cost recovery in a manner very similar to that of Duke Energy Indiana which received an authorized ROE of 10.5% in its 2004 rate order. He said ROE has been set at 10.4% in the Settlement in recognition of the ability to recoup various types of costs. However, Mr. Benkert contended, given Petitioner's small size, the continued required investment in its generation and distribution system, as well as non-RECB transmission projects that it must finance, the many types of costs at risk, such as chemicals and catalyst, and margin risk that remains, the 10.4% ROE opportunity is not excessive.

Mr. Benkert said the OUCC and Petitioner have worked together throughout the case to understand the goals of Petitioner in terms of proactively maintaining facilities, moving forward with a data collection process to better direct future maintenance activities, and addressing Petitioner's aging workforce issues and other hiring needs. Mr. Benkert testified that the commitment to file a base rate case in five years provides assurance that after having hired personnel and implemented the programs, the opportunity exists for a comprehensive review of

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[6] Ind. Code § 8-1-2-42.3 requires that when a base rate case order is received, the earnings bank be reset to reflect the accumulated difference between authorized and actual NOI during each FAC period of the last five years.

Petitioner's costs. In the meantime, Petitioner will provide the OUCC with the ongoing reporting agreed upon in the Settlement.

Mr. Benkert also discussed the Settlement provisions that protect against the NOI test operating in a way that would prevent Petitioner from recovering a return on Petitioner's investment in approved environmental projects, costs related to RECB, and Petitioner's share of WPM in excess of the Non-Firm Credit. Mr. Benkert noted that the NOI test remains in place to govern Petitioner's financial performance, but clearly delineated special cost recovery issues are recognized and dealt with in the Settlement in a constructive manner.

Mr. Benkert testified the Settlement provides that the parties request that prompt approval of the Settlement be seriously considered and acted upon. He explained that Petitioner has agreed to a much smaller increase than originally proposed, has withdrawn its ROE test proposal and modified other proposals in ways that are either disadvantageous to or subject Petitioner to increased risk. He asserted significant motivation for Petitioner to agree to the Settlement is its expectation that the Settlement will lead to prompt authorization of the agreed-upon rate increase, as has been the case in other rate proceedings of Petitioner that were resolved by Settlement. He stated Petitioner is a strong proponent of resolving rate proceedings amicably by settlement if at all possible.

At the hearing on the Settlement, Mr. Benkert was asked about the inclusion of $9.5 million of demolition costs for the Ohio River Station ("ORS") in the depreciation study. Mr. Benkert explained that ORS was originally constructed as a generating plant in 1929 but had not been used for generation since 1984. Petitioner now intends to demolish the structure and will need to comply with asbestos abatement requirements. The plant was properly depreciated until 1995, the date of Petitioner's last rate case, using an all production plant composite depreciation rate. In the 1995 case, separate depreciation rates by generating station were approved by the Commission and as a result of that order, depreciation on ORS properly ceased upon issuance of that order. At that time, the accumulated cost of removal recorded through the recovery of depreciation expense was $1.3 million. Mr. Benkert said that while $1.3 million in cost of removal for ORS has been accumulated in the depreciation reserve (resulting in a rate base reduction), the actual bid from the demolition contractor is well in excess of that amount. Mr. Benkert said it was proper to consider the current cost of removal in the depreciation study and that the $1.3 million already accrued is in effect netted against it as a reduction to rate base.

Mr. Benkert was also asked about the requirement to file another rate case by December 31, 2012. He said the onus was on Petitioner to file a rate case by that time unless the settling parties agreed otherwise in which event an explanation for the extension would be presented to the Commission.

Janice M. Barrett, Petitioner's Manager, Regulatory Accounting, reviewed the terms of the Settlement and sponsored an exhibit showing the test year income statement and each of the adjustments made to determine pro forma results at current and settlement rates. She also provided exhibits showing the calculation of the cost of capital and original cost rate base used in the Settlement. She demonstrated how each revenue and expense adjustment in the Settlement compared to Petitioner's original filing, the OUCC's case-in-chief and Petitioner's rebuttal. She also discussed how the Settlement would roll into base rates the NO_x project authorized in Cause No. 42248, Phase II, the Culley Unit 3 fabric filter authorized in Cause No. 42861, the existing DSM rider and certain demand costs currently recovered in the FAC.

Mr. Doty testified about how the Settlement addresses the aging workforce issue, proposed system maintenance programs and transmission reliability improvements. He said that the Settlement provides for a cooperative approach to the direction of the maintenance programs, calling attention to the agreed-upon reporting procedures.

Mr. Ulrey discussed the Settlement cost of service allocations and rate design. He provided a revenue proof showing how the revenue increase was distributed among the Customer Facilities Charges, Demand Charges (as applicable) and Energy Charges for the various rate schedules. Mr. Ulrey stated this distribution was made in the same manner as proposed in Petitioner's case-in-chief and continued the objective of having the bill impacts to any customer be no more than approximately two times the overall rate schedule increase. Mr. Ulrey also sponsored a schedule showing the bill impacts for each of the rate schedules at various levels of monthly usage. The schedule showed that a typical Residential Rate A customer's bill will increase by just over $17 per month.

Mr. Ulrey also sponsored the Settlement Tariff (*Petitioner's Exhibit JLU-4*) and a black-lined copy showing changes from the current tariff (*Petitioner's Exhibit JLU-5S*). In his supplemental testimony, Mr. Ulrey also identified the revisions, deletions and additions made in the Settlement Tariff. Mr. Ulrey also provided testimony on how the agreed-upon MCRA and RCRA would operate and the types of costs and credits that would be included in each.

(ii). **OUCC's Evidence.** Ms. Soller testified for the OUCC in support of the Settlement. She said the Settlement was reached as a result of lengthy good faith negotiations between all parties, most of which took place after all parties filed their testimonies and were well informed of the issues. She pointed out the Settlement contained a detailed description of how the parties systematically resolved each issue. She called attention to the reduction in the cost of the maintenance programs achieved by the Settlement which, she said, were consistent with electric industry standards. Ms. Soller also focused on the customer benefits resulting from Settlement provisions on emission allowances, wholesale power sales, school safety education and new customer service options.

Ms. Soller testified about how the Settlement changed the funding levels for Petitioner's proposed energy delivery maintenance programs which are needed to adequately maintain system integrity, maximize existing investments and improve or upgrade facilities. She characterized the progress reporting provisions as a critical component of the Settlement, and said the OUCC hoped other electric utilities in the State would make similar commitments at appropriate times. She stated the Settlement provisions regarding the programs strike a balance between what is needed to make immediate improvements to increase reliability and encouraging accountability through progress reporting. Ms. Soller testified that the Settlement Agreement provided the Petitioner with the flexibility to hire needed personnel but on a more gradual schedule that will minimize the cost impact to customers. She also stated that Petitioner's relying less on contracted labor and more on internal employees will address concerns raised at the field hearing about service restoration efforts being affected by the lack of geographic familiarity of contractors.

With respect to the RCRA, Ms. Soller stated that the OUCC had no objection to the tracking of costs and revenues which will vary annually and which the Commission has historically permitted, but opposed chemical cost tracking. She said due to the OUCC's position, Petitioner agreed to withdraw its tracking request for chemical costs. She also indicated that the

Petitioner accepted the OUCC's position that Direct Load Control Credits should be tracked separately in the DSMA which is similar to DSM program treatment for other Indiana utilities.

Ms. Soller testified that WPM sharing, municipal contract crediting and the treatment of emission allowances will likely result in credits to customers for the first several years under the Settlement. Ms. Soller expressed the OUCC's belief that 50/50 sharing of increases above or decreases below the $10.5 million per year Non-Firm Credit provides shared risk and reward for both Petitioner and ratepayers. She also pointed out the similarity of the MCRA to Duke Energy Indiana's RTO tracker and noted that Section 26 RECB revenues and charges included in the MCRA are based directly on a FERC-approved tariff. Ms. Soller discussed the extensive review and approval process for RECB projects in which all stakeholders, including the OUCC, can actively participate. She said the OUCC expects future stakeholder review to include a forum for input from the Commission and other interested Indiana parties and assurance of prudent decision making across the MISO footprint. She also stated that non-RECB transmission projects undergo the MISO stakeholder review process, but will not be included in the agreed-upon RCRA.

With respect to ROE, Ms. Soller summarized the various evidentiary positions of the parties. She then stated that through an exchange of information, discussion of risk reduction due to tracking mechanisms, and a review of ROEs being awarded to electric utilities around the country, it was agreed that 10.4% was well within the range of reasonableness.

Ms. Soller said the Settlement provides for continuation of the NOI test and the OUCC believes any discussion of a change should take place in a forum where all interested parties can participate. She testified the Settlement is intended to prevent the NOI test from depriving Petitioner of the opportunity to share in WPM profits as provided in the Settlement. She thought this would serve as an incentive for Petitioner to actively pursue wholesale sales and minimize downside risks for ratepayers. Ms. Soller said the OUCC supported the commitment for Petitioner to file a rate case in five years because it has been over a decade since its last rate case and a subsequent rate case will allow timely review of system maintenance projects and evolving MISO matters.

In conclusion, Ms. Soller on behalf of the OUCC recommended the Commission approve the Settlement as filed because it serves the public interest by (a) reducing the rate impact, (b) encouraging operational reliability improvements, (c) adding customer service payment options and service personnel, and (d) including a fair, but not excessive, ROE to facilitate the ability of Petitioner to attract capital required for necessary infrastructure improvements.

(iii). **The PPG Settlement.** Thomas L. Bailey, Manager of Industrial Sales, described the PPG Settlement and the PPG Agreement attached thereto. Mr. Bailey stated that PPG operates an original equipment automotive glass manufacturing facility in Evansville ("Evansville Facility" or "Facility") and is a major employer in the area, a long-time customer of Petitioner and one of Petitioner's largest customers. Mr. Bailey discussed the competitive challenges faced by PPG's automotive glass business due to the decline in the domestic automobile industry, foreign competition and the forces of globalization and commoditization. According to Mr. Bailey, PPG has publicly stated in its SEC filings that its automotive glass business is an underperforming business unit for which alternatives are being considered, including downsizing. Mr. Bailey testified that if that occurs, PPG would evaluate the energy costs of its facilities and PPG has advised Petitioner that projected electric service costs to its

Evansville Facility exceed those of its glass plants in Kentucky and Pennsylvania. Mr. Bailey sponsored an affidavit of PPG's Vice President of Automotive OEM Glass Products regarding PPG's competitive issues and business plans ("PPG Affidavit").

Mr. Bailey explained that because significant downsizing of the PPG Facility or the loss of the PPG Facility as a customer would adversely affect Petitioner and its other customers, Petitioner engaged in good faith, arms length negotiations with PPG about what would be required to keep the PPG Facility as a customer on terms that would be reasonably economic for Petitioner. Mr. Bailey reported these negotiations were successful and culminated in the execution of the PPG Settlement and PPG Agreement.

Mr. Bailey testified that the loss or reduction of PPG as a customer would adversely affect Petitioner's other customers because most of Petitioner's costs of providing electric utility service are fixed and will not be materially reduced if PPG ceases production at the Facility. Mr. Bailey stated that if PPG can be induced to maintain production at the PPG Facility through rates under which Petitioner will recover more than the incremental cost of continuing to serve PPG, the other customers will be better off as a result of the preservation of PPG's contribution to Petitioner's fixed cost recovery. He said the PPG Agreement will encourage PPG to continue operations at the PPG Facility and thereby protect jobs in the Evansville area.

Mr. Bailey testified the PPG Agreement will address electric costs that otherwise would be less competitive at the Evansville Facility than other PPG automotive glass plants. Mr. Bailey also pointed out the PPG Agreement imposes a minimum purchase obligation on PPG for a specific term of years, further discouraging PPG from closing or reducing operations at the Evansville Facility during the agreement's term.

Mr. Bailey testified the PPG Agreement will not be effective until (a) approval by the Commission and (b) the effective date of the new Tariff for Electric Service approved in this cause. He explained the Facility will be served under Rate LP, Large Power Service, except to the extent expressly modified by the PPG Agreement. The rates and charges consist of (a) a Customer Facilities Charge; (b) a Demand Charge; (c) a Transmission Voltage Discount for delivery at 69kV or higher; and (d) an Energy Charge for all kWh used per month. Absent submission of a mutually agreed upon extension to the Commission for approval at least six months prior to the end of the initial term, the PPG Agreement will expire and PPG will revert to the standard applicable Rate LP rates. PPG will pay a monthly minimum purchase obligation unless excused by an event of force majeure, regardless of PPG's actual usage. The PPG Agreement also contains provisions to promote the retention of employees at the PPG Facility and relating to certain payments by PPG if the PPG Agreement is terminated under certain circumstances.

Mr. Bailey stated Petitioner's revenues under the terms of the PPG Agreement will exceed the incremental cost to Petitioner of continuing to serve the Facility. He noted that because PPG is an existing customer, no new investment is required to continue to serve PPG. According to Mr. Bailey, the PPG Agreement will not adversely impact the adequacy or reliability of service to other customers. He opined that the rates contained in the PPG Agreement are practical and advantageous to PPG and Petitioner, in the public interest, and not inconsistent with the purpose of Indiana utility regulation. He emphasized that the PPG Agreement provides benefits to Petitioner's customers and the southwestern Indiana economy. He explained that the PPG Agreement and Settlement were the result of arms-lengths

negotiations between two parties that are sophisticated in negotiating energy contracts and represent a result that is the best deal both sides felt could be obtained.

Mr. Bailey also identified the parts of the PPG Agreement that Petitioner requested be treated as confidential information. Mr. Bailey said these confidential provisions contain pricing, demand, term and other provisions that were negotiated between PPG and Petitioner on a confidential basis. He stated Petitioner is likely to negotiate business retention contracts with other customers in the future and public disclosure of these terms would allow parties that Petitioner is negotiating with to use this information against Petitioner in negotiations, thereby limiting the potential revenues and benefits that could accrue to Petitioner and its customers. He also identified parts of the PPG Affidavit which are confidential because they discuss and analyze confidential cost, usage, operational and business planning information of PPG. Mr. Bailey pointed out that disclosure of PPG's confidential cost, usage, operational and business planning information could be of value to its competitors and harmful to PPG. In sum, according to Mr. Bailey, Petitioner and PPG both derive economic benefit from the confidential information not being publicly available.

Mr. Bailey testified the confidential provisions have been the subject of efforts that are reasonable under the circumstances to maintain their secrecy. Mr. Bailey said that within Petitioner, this information has been and will continue to be disclosed only to those persons directly involved with negotiating, obtaining approval of, and monitoring compliance with, the PPG Agreement. He also indicated Petitioner has entered into an agreement with PPG that protects the confidentiality of the PPG information.

7. **Commission Findings Regarding the Settlement Agreement.** Pursuant to the Commission's procedural rules, and prior determinations by this Commission, settlement agreement will not be approved by the Commission unless it is supported by probative evidence. 170 IAC 1-1.1-17. Settlements presented to the Commission are not ordinary contracts between private parties. *United State Gypsum, Inc. v. Indiana Gas Co.*, 735 N.E.2d 790, 803 (Ind. 2000). Any settlement agreement that is approved by the Commission "loses its status as a strictly private contract and takes on a public interest gloss." *Id.* (quoting *Citizens Action Coalition v. PSI Energy, Inc.*, 664 N.E.2d 401, 406 (Ind. Ct. App. 1996)). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action Coalition,* 664 N.E.2d at 406. Furthermore, any Commission decision, ruling or order – including the approval of a settlement – must be supported by specific findings of fact and sufficient evidence. *United State Gypsum,* 735 N.E.2d 790 at 795 (citing *Citizens Action Coalition v. Public Service Co.*, 582 N.E.2d 330, 331 (Ind. 1991)). Therefore, before the Commission can approve the Settlement Agreement, we must determine whether the evidence in this Cause sufficiently supports the conclusion that the Settlement Agreement is reasonable, just, and consistent with the purpose of Indiana Code § 8-1-2-1 *et seq.*, and that such agreement serves the public interest.

In the present proceeding, our review of the reasonableness of the Settlement Agreement is aided by the parties' express agreement on the rate base and rate of return to be used in determining Petitioner's revenue requirement and each pro forma adjustment to test year results used to determine the adjusted financial results at present and settlement rates.[7] The agreed-upon

[7] Ind. Code § 8-1-2-6 requires the Commission to value a public utility's property at its "fair value."

pro forma adjustments represent amounts calculated in the OUCC's case-in-chief, Petitioner's rebuttal or otherwise grounded in the evidence and the details underlying the adjustments are in the evidentiary record. Therefore, we have been able to examine the basis for all of the components of the increase in basic rates and charges provided for in the Settlement and see exactly how each disputed issue was resolved. We find the Settlement provisions regarding Petitioner's basic rates and charges are reasonable for purposes of settlement and amply supported by the evidence of record.

We also find the other provisions of the Settlement, including the RCRA, the MCRA and the DSMA provisions, to be just and reasonable in the context of the Settlement as a whole. We also recognize that many of the items included in the RCRA were included in similar trackers approved by the Commission. *See. PSI Energy, Inc.*, Cause No. 42359 (*Ind. Util. Reg. Comm'n*, May 18, 2004). Likewise, the non-firm wholesale margin sharing provision is comparable to what has been authorized for Duke Energy Indiana. *Id.* at 117. Further the Petitioner pointed out that it is highly likely that, for at least the near term, the RCRA will result in a net credit or rate decrease for customers.

The MCRA is similar to the MISO tracking mechanism approved for Duke Energy Indiana. *PSI Energy Inc.*, Cause No. 42359 at 120. The MCRA deals with costs that are the result of decisions by FERC, variable in amount from year to year, variable as to timing, substantial in individual and aggregate amounts and outside the control of Petitioner. Therefore, the MCRA satisfies the criteria applied in Duke Energy Indiana's case. *Id.* The RECB costs (MISO Tariff Schedule 26) relate to a new charge that we have not previously addressed, but, as pointed out by Petitioner's witnesses as well as OUCC Witness Soller, RECB revenues and charges are based directly on a FERC-approved tariff, relate to a federal program to improve network reliability and the proposed transmission upgrades are subject to an extensive review and approval process. As discussed by OUCC Witnesses Soller and Blakley, placing the direct load control billing credits in the DSMA results in treatment comparable to that of other Indiana electric utilities.

The Commission also notes that the parties incorporated into the Settlement Agreement new bill payment and customer service options that are responsive to comments made by customers at the Field Hearing conducted in this Cause. These options include a centrally located automated pay station, new bill payment sites in Evansville and Mt. Vernon where customers can pay bills at locations where water bills are currently collected and dedication of new customer service representatives trained to meet face-to-face with customers and discuss complaints. The Settlement Agreement also addresses Petitioner's request, with some adjustments, regarding its aging workforce by recruiting, training and developing replacements for the skilled workers who are expected to retire in upcoming years.

Therefore, absent settlement of the issues among the parties, the original cost determination utilized in this Cause and discussed throughout this Order would not necessarily, in and of itself, be an accurate reflection of the "fair value" of the Petitioner's property. However, as this matter has been resolved by agreement the Commission is satisfied that, based on the specific facts presented in this matter, "original cost" also constitutes an accurate reflection of the "fair value" of the Petitioner's property for purposes of our consideration of the Settlement Agreement and the requirements set-forth in Ind. Code § 8-1-2-6.

We further find that for purposes of the earnings test component of the FAC, Petitioner's authorized annual net operating income shall be $76,400,199.[8] The Settlement Agreement provisions regarding the treatment of Schedule 26 recoveries as non-jurisdictional and outside of the NOI test; the NOI test adjustments for four years for Petitioner's share of non-firm wholesale power margins in excess of the $10.5 million Non-Firm Credit; and NOI test adjustments to allow Petitioner to retain its recovery of costs of Senate Bill 29 projects (Ind. Code 8-1-8.8) represent a reasonable approach, in the context of the whole Settlement, to protect against the NOI test operating in a way that negates the intent of the Settlement. We find that these provisions are, as part of the overall negotiated package of terms that the parties have documented with significant detail in this Settlement, reasonable and in the public interest.

In approving the 50/50 sharing of non-firm wholesale power margins as part of the Settlement Agreement, the Commission finds that tracking shall be above and below the net $10.5 million in base rates; Vectren shall not apply a net annual off-system sales profit of less than zero to the RCRA; and, all off-system sales net income shall be included as jurisdictional income for purposes of the FAC earnings test. To the extent necessary, we adopt them pursuant to Ind. Code § 8-1-2.5-6 as alternative regulatory practices, procedures and mechanisms and find they satisfy the public interest standard set forth therein.

In accordance with the Settlement, we also approve and authorize Petitioner to use the revised depreciation accrual rates provided in Petitioner's rebuttal testimony, which include use of a 5.83% depreciation rate for the Culley Unit 3 fabric filter as recommended by the OUCC. While the OUCC's depreciation witness raised other issues about the depreciation study, the Settlement indicates that the OUCC's concerns were addressed by Petitioner's rebuttal testimony and in the settlement discussions.

With respect to the inclusion in the depreciation study of the cost to demolish ORS, the evidence shows ORS was used to provide generation for Petitioner's customers for over 50 years, the ORS site contains significant ongoing electric operations including two peaking units, transmission equipment and a switchyard, the facility needs to be removed for health and safety reasons, and the Petitioner indicated that it has netted out the accrued reserve against its proposed cost of removal. In light of these specific circumstances and the Settlement reached in this Cause, we find that the estimated ORS removal cost shall be included in deprecation rates.

In reaching this conclusion we recognize that the ORS has not been used for generation since 1984 and that the plant was properly depreciated until 1995, the date of Petitioner's last rate case, using an all production plant composite depreciation rate. At that time, the accumulated cost of removal recorded through the recovery of depreciation expense was $1.3 million. In an effort to avoid intergenerational inequities the removal of ORS seemingly should have occurred prior to 1995 or been addressed in the Petitioner's last rate case. Instead, the issue has been allowed to linger for over 20 years since the date ORS was last used to generate electricity. Therefore, in order to monitor the Petitioner's efforts at undertaking and completing the removal of the ORS, we find that it shall file annual reports with the Commission, beginning on December 31, 2007 and continuing through December 31, 2012 (as necessary if the project

[8] For purposes of computing the authorized net operating income for IC 8-1-2-42(d)(3), the Commission finds that the increased return shall be phased-in over the appropriate period of time that the Petitioner's net operating income is affected by the earnings modification as a result of the Commission's approval of this Order.

has not been completed), regarding its efforts and ongoing expenditures to remove the ORS. In addition, at its next rate case the Petitioner shall present a demolition cost study for all units, as is necessary and appropriate in rate proceedings, to allow for long term planning for any necessary future demolition costs.

At the Evidentiary Hearing on the Settlement, the bench inquired about the provision that required the Petitioner to file another base rate case no later than December 31, 2012 and further providing that should the parties mutually agree to extend that deadline, they will inform the Commission of the extension and the basis therefore prior to that date. The Settlement does not specify how much advance notice would be given to the Commission of such an agreement. Consistent with comments made by Ms. Soller that the OUCC was open to providing advance notice, Petitioner's counsel indicated Petitioner's willingness to report to the Commission by June 15, 2012 on the nature and status of discussions among the parties on the timeline for the next rate case in the event it has not been filed by that date. The other settling parties expressed agreement with this approach. Petitioner further committed to provide the Commission with the rationale for any agreed-upon extension of the filing deadline so that the Commission would have the opportunity to review the Parties' explanation of their rationale for delaying the filing of the next rate case, in the event such an agreement is reached. We find that advance notice to the Commission in accordance with this timeframe would be appropriate and in the public interest.

Accordingly the Petitioner and the other parties shall comply with this reporting commitment and any additional reporting requirements agreed upon or necessitated by the Settlement Agreement or the terms of this Order. Such reporting commitments include ORS demolition status and cost updates and reports to be filed with the OUCC regarding certain system metrics and progress on maintenance programs as set-forth in Appendix D of the Settlement Agreement. Both of these reporting requirements shall be made in this Cause as a compliance filing. In addition, the amortization periods in this Cause vary from four (4) years for the recovery of MISO Day 1 and Day 2 Costs as agreed upon by the OUCC and the Petitioner; to five (5) years for Demand Side Management costs; and three (3) years for New Source Legal Costs and Rate Case Expenses as originally proposed by the Petitioner and left undisturbed by the Settlement Agreement. Therefore, in order to effectuate the terms of the Settlement Agreement the Commission recognizes that it will be necessary for the Petitioner to submit compliance filings, along with a revised tariff, for approval by the Commission, that reflect revised rates as a result of the expiration of each respective amortization period. Such compliance filings may be made in this Cause at the end of each respective amortization period.

In conclusion, we find that the Settlement Agreement is reasonable, supported by the evidence of record and in the public interest and should be approved. We further find that the new Tariff For Electric Service, I.U.R.C. No. E-12, filed on April 26, 2007 with Petitioner's supplemental testimony on the settlements, including but not limited to the rates and charges set forth therein, is fair, just and reasonable and should be approved subject to the terms and conditions contained in the Settlement. We also approve the rolling into base rates of the NO_x project approved in Cause No. 42248, Phase II, and the Culley Unit 3 fabric filter approved in Cause No. 42861. Accordingly, Petitioner's Qualified Pollution Control Property trackers for the NO_x project shall be discontinued and its Qualified Pollution Control Property trackers for its Multipollutant Projects shall be revised to eliminate the Culley Unit 3 fabric filter.

The Parties indicate in the Settlement Agreement that it shall not constitute an admission or a waiver of any position that any of the Parties may take with respect to any or all of the items and issues resolved therein in any future regulatory or other proceedings, except to the extent

necessary to enforce its terms. With regard to future citation of the Settlement Agreement, we find the Settlement Agreement and our approval of it should be treated in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434 (*Ind. Util. Reg. Comm'n,* March 19, 1997).

8. Commission Findings on the PPG Settlement. We have reviewed *in camera* the parts of the unredacted versions of the PPG Agreement and the PPG Affidavit that Petitioner has designated as confidential trade secret information ("Confidential Information"), and we find that disclosure of the Confidential Information would have a substantial detrimental effect on Petitioner by placing it at a disadvantage in future negotiations of special contracts with other industrial customers, thereby limiting the potential benefits that could accrue to ratepayers, shareholders and Petitioner in other cases. We further find that the disclosure of the Confidential Information in the PPG Agreement and the PPG Affidavit would have a substantial detrimental effect on PPG by making available to its competitors PPG's confidential cost, usage, operational and business planning information. The Confidential Information is such that it may derive actual and independent economic value from being neither generally known to, nor readily ascertainable by, persons who could obtain economic value from its disclosure or use. We further find the Confidential Information is the subject of efforts that are reasonable under the circumstances to maintain its secrecy. Therefore, we find that the Confidential Information constitutes trade secrets within the meaning of Ind. Code § 5-14-3-4(a) as defined by Ind. Code § 24-2-3-2. We accordingly find that the Confidential Information should be exempt from public access under Ind. Code § 8-1-2-29 and shall be held confidential and protected from public disclosure by the Commission.

Ind. Code § 8-1-2-24 ("Section 24") provides:

> Nothing in this chapter shall be taken to prohibit a public utility from entering into any reasonable arrangement with its customers or consumers, or with its employees, or with any municipality in which any of its property is located, for the division or distribution of its surplus profits, or providing for a sliding scale of charges or other financial device that may be practicable and advantageous to the parties interested. No such arrangement or device shall be lawful until it shall be found by the commission, after investigation, to be reasonable and just and not inconsistent with the purpose of this chapter. Such arrangement shall be under the supervision and regulation of the commission.

Ind. Code § 8-1-2-25 provides:

> The commission shall ascertain, determine and order such rates, charges and regulations as may be necessary to give effect to such arrangement, but the right and power to make such other and further changes in rates, charges and regulations as the commission may ascertain and determine to be necessary and reasonable, and the right to revoke its approval and amend or rescind all orders relative thereto, is reserved and vested in the commission, notwithstanding any such arrangement and mutual agreement.

The PPG Agreement specifies the terms, conditions and rates of the electric service to be provided to the PPG Facility and has been filed with the Commission for approval. An inspection of the Confidential Information demonstrates that the rates provide for the recovery of

incremental costs of serving PPG plus a contribution to the recovery of Petitioner's fixed costs. The Agreement is the result of arms length negotiations and will result in a direct benefit to Petitioner's other customers for the reasons discussed by Mr. Bailey, including by the preservation of PPG's contribution to Petitioner's fixed cost recovery.

We find the PPG Agreement and the rates and terms and conditions contained therein are just and reasonable, practical and advantageous to the parties and not inconsistent with the purposes of the Public Service Commission Act, Ind. Code Chap. 8-1-2 and we find the Agreement to be in the public interest and supported by the evidence of record. We therefore find that the Agreement should be approved in its entirety pursuant to Ind. Code §§ 8-1-2-24 and -25.

9. FERC Seven-Factor Test. In its Petition, Petitioner requested that the Commission approve Petitioner's proposed classification of its facilities as transmission or distribution in accordance with the Seven-Factor Test set forth in FERC Order No. 888. *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities*, Docket No. RM95-8-000, Order No. 888, FERC Stats. & Regs., Regs. Preambles, Transfer Binder 1991-1996 ¶31,036 at 31,770 (April 24, 1996). Petitioner stated that the agreement of the transmission owners under which MISO was organized requires each transmission owner, including Petitioner, to request such approval from its appropriate regulatory authority. Petitioner's Witness Chambliss testified on Petitioner's application of the Seven-Factor Test to determine the classification of its facilities. None of the parties expressed any concerns about Petitioner's proposed classification. We find Petitioner's proposed classification is reasonable and should be approved in the context of the settlement of all issues in this Proceeding.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION THAT:

1. The Stipulation and Settlement Agreement between Petitioner, the OUCC and Industrial Group filed in this cause on April 20, 2007, and attached hereto and incorporated by reference, is hereby accepted, approved and adopted by the Commission consistent with the findings set-forth herein.

2. The proposed Tariff For Electric Service as filed by Petitioner on April 26, 2007 with its supplemental testimony on the Settlement Agreement is approved and authorized and shall be effective upon its filing with the Commission's Electricity Division.

3. Petitioner is hereby authorized to implement the rates and charges for electric utility service described herein, in the Settlement Agreement and in the Tariff for Electric Service upon the filing of the new Tariff with the Electricity Division. In accordance with the Settlement Agreement, the Petitioner shall file the first 6 months of estimated credits from municipal wholesale sales and EEA credits at the same time new rates resulting from this proceeding become effective.

4. Petitioner is hereby authorized to implement the Reliability Cost and Revenue Adjustment ("RCRA"), Demand Side Management Adjustment ("DSMA") and MISO Cost and Revenue Adjustment ("MCRA"), as provided in the Settlement Agreement. Filings under the RCRA, DSMA and MCRA shall utilize the corresponding acronym along with the assigned

Cause number, with the initial filing in each matter designated as 01. Future filings in these adjustment proceedings shall continue to utilize the initially assigned Cause number along with the subsequent numerical designation.

5. To the extent necessary, the provisions of the Settlement Agreement regarding the NOI test are approved, as alternative regulatory practices, procedures or mechanisms pursuant to Ind. Code § 8-1-2.5-6.

6. Petitioner's proposed depreciation accrual rates as modified in its rebuttal testimony are hereby approved and authorized.

7. The PPG Agreement is consistent with the purpose of the Ind. Code § 8-1-2 and in the public interest. The Agreement is hereby approved by the Commission in all respects.

8. The Confidential Information contained in the PPG Agreement and the PPG Affidavit described herein is determined to be confidential trade secret information as defined in Ind. Code § 24-2-3-2 and therefore exempt from public access and disclosure pursuant to Ind. Code § 5-14-3-1 and § 8-1-2-29.

9. Petitioner's proposed classification of its facilities as transmission and distribution by application of FERC's Seven-Factor Test is hereby approved.

10. The Petitioner shall comply with all additional conditions and requirements set-forth in this Order.

11. This Order shall be effective on and after the date of its approval.

HARDY, GOLC AND ZIEGNER CONCUR; LANDIS AND SERVER ABSENT:
APPROVED: AUG 1 5 2007

I hereby certify that the above is a true and correct copy of the Order as approved.

Brenda A. Howe

Brenda A. Howe,
Secretary to the Commission

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FILED

APR 20 2007

INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. ("VECTREN SOUTH – ELECTRIC") FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES APPLICABLE THERETO; (3) INCLUSION IN ITS BASE RATES OF COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY PROJECTS; (4) AUTHORITY TO IMPLEMENT A RATE ADJUSTMENT MECHANISM TO TRACK INCREMENTAL CHANGES IN CERTAIN COSTS AND REVENUES RELATING TO ITS GENERATING FACILITIES; (5) AUTHORITY TO IMPLEMENT A RATE ADJUSTMENT MECHANISM TO TRACK INCREMENTAL CHANGES IN NON-FUEL RELATED MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC. ("MISO") CHARGES AND PETITIONER'S TRANSMISSION REVENUE REQUIREMENT; (6) APPROVAL AS AN ALTERNATIVE REGULATORY PLAN PURSUANT TO IND. CODE § 8-1-2.5-6 OF A RETURN ON EQUITY TEST TO BE USED IN LIEU OF THE STATUTORY NET OPERATING INCOME TEST IN ITS FUEL ADJUSTMENT CHARGE PROCEEDINGS; (7) APPROVAL OF REVISED DEPRECIATION ACCRUAL RATES; (8) APPROVAL OF THE CLASSIFICATION OF PETITIONER'S FACILITIES AS TRANSMISSION OR DISTRIBUTION IN ACCORDANCE WITH THE FEDERAL ENERGY REGULATORY COMMISSION'S SEVEN FACTOR TEST; AND (9) APPROVAL OF VARIOUS CHANGES TO ITS TARIFF FOR ELECTRIC SERVICE INCLUDING NEW INTERRUPTIBLE AND ECONOMIC DEVELOPMENT RIDERS.	CAUSE NO. 43111

STIPULATION AND SETTLEMENT

The Indiana Office of Utility Consumer Counselor ("OUCC"), Intervenor Industrial Group ("IG"), and Vectren Energy Delivery of Indiana, Inc., a/k/a Southern Indiana Gas and Electric Company, Inc. ("Company" or "Vectren South") (collectively, the "parties"), in the interest of efficiency and in order to consider a number of policy issues raised in the Company's testimony, have devoted significant time to the review of data and discussion of issues, and have succeeded in reaching agreement on all issues in this proceeding and therefore stipulate and agree to the terms and conditions set forth below.

In this proceeding, this Stipulation follows the initial hearing on Vectren South's Case-In-Chief, the OUCC's and IG's filing of testimony in response to the Company's case, and the Company's filing of rebuttal testimony. Those filings framed the discussions between the parties, and formed the basis for the parties to reach agreement on the terms reflected in this Stipulation. As set forth in Appendices A, B and C, the parties have negotiated terms that resolve all issues related to the revenue requirement. Specifically, as to pro forma adjustments to the test year proposed in this case, with a few exceptions the agreed upon adjustments either reflect the testimonial rebuttal position of the Company or the testimonial position of the OUCC, and thus are founded upon documented positions that are in the record in this proceeding. The parties have agreed that the OUCC's and IG's testimony, and the Company's rebuttal testimony, will be submitted into the record in support of this Stipulation.

The terms of the Stipulation are as follows:

1. Rate Increase.

Petitioner shall be authorized to increase its basic rates and charges (collectively "rates") for electric utility service. The rates shall be designed to produce base revenues of $479,915,205. The increase provides for additional annual revenues of $67,255,394 or $60,794,647, this lesser amount being net of the expected credit in the first year as municipal contract revenues are passed back to customers. Based on additional revenues of $60,798,647, the overall revenue increase is approximately 15%. The base rate increase reflects the roll-in of certain NOx and multi-pollutant control equipment capital and operating costs currently being recovered under Ind. Code §8-1-8.8 et. seq., as well as the recovery of deferred Demand Side Management costs, deferred MISO costs and base amounts of purchase power demand costs. These rates reflect allocation of the revenue increase among all rate classes based on a Settlement cost of service, including a 25% subsidy reduction.

The agreed-upon rate increase reflects the following original cost rate base, cost of capital and financial results (See Appendices A & B) which the Parties agree are reasonable for purposes of compromise and settlement:

Rate Base as of October 31, 2006

	$(000's)
Utility Plant in Service	$1,783,735
Less: Accumulated Depreciation	812,809
Net Utility Plant	970,926
Materials and Supplies	42,987
DSM Regulatory Asset	29,156
Other Regulatory Assets	650
Total	$1,043,719

Capital Structure as of March 31, 2006

	Amount ($000's)	Weight	Cost	Weighted Cost
Common Equity	$ 549,508	47.05%	10.40%	4.89%
Long Term Debt	451,347	38.65%	6.04%	2.34%
Customer Deposits	5,601	0.48%	5.39%	0.03%
Cost Free Capital	152,477	13.06%	0.00%	0.00%
Post 1970 JDITC	8,920	0.76%	8.43%	0.06%
	$1,167,853			7.32%

Pro Forma Proposed Rates

	$(000's)
Revenue	$ 479,915
Gas Cost	158,632
Gross Margin	321,283
O&M	131,232
Depreciation	64,274
Income Taxes	34,501
Other Taxes	14,876
Total Operating Expense	244,833
Net Operating Income	$ 76,400

Authorized Return. Effective upon implementation of the rates, which shall be set forth in a form of tariff for Electric Service, I.U.R.C. No. E-12, ("Tariff") described hereafter and submitted with the testimony filed in support of the Settlement, the Company's authorized return for purposes of the earnings test component of the gas cost adjustment (Ind. Code §§ 8-1-2-42(g)(3)(C) and -42.3) shall be $76,400,199. (See Appendix A, page 3 of 3). This represents a return of approximately 7.32% on an original cost rate base of $1,043,718,562. The Parties agree, solely for purposes of settlement and compromise, that this represents a reasonable return on Company's investment in used and useful property, plant and equipment.

Depreciation Rates. Vectren South's depreciation rates have been adjusted to the asset category-specific depreciation rates consistent with the Company's Rebuttal Testimony in this Cause.

2. Pro Forma Adjustments.

All the agreed upon adjustments are set forth in Appendix C. The OUCC filed testimony contesting a number of the Company's proposed adjustments. As set forth in Pub. Ex. 6, Schedule TSC-31, the OUCC recommended almost $11 million of adjustments to the Company's O&M pro formas. The Company responded in its rebuttal filing, supporting many of the disputed pro forma amounts but also agreeing to decrease its O&M pro formas in the case by approximately $5.8 million. The parties then negotiated the remaining pro forma differences, with the Company decreasing its O&M pro formas by an additional $1.6 million in the Settlement. Appendix C provides a comparison of the Company's pro forma adjustments as set forth in its original case-in-chief to the OUCC's filed positions, as well as the Company's positions on rebuttal, and to the final negotiated Settlement amounts for each pro forma adjustment. Intervenor IG did not file testimony related to the Company's pro formas.

The material pro forma reductions as a result of both the Company's rebuttal and settlement concessions are discussed specifically below. While an explanation of these individual adjustments is provided, the negotiated amounts represent agreements reached by the parties as part of the overall settlement package of terms.

Fuel Handling Expense (A11)

The Company included a $332,391 pro forma adjustment based on projected increases in fuel prices. The OUCC eliminated the adjustment based on 2006 expense data. The Company agreed to remove the entire pro forma amount.

Ongoing MISO Day 2 Costs (A13)

The Company projected ongoing Day 2 costs based on test year experience. The OUCC used 2006 cost information to reduce the base rate amount of MISO Day 2 costs from $5,420,266 to $2,668,969. The Company agreed to this reduction. The parties have agreed that variances from base rate amounts in ongoing Day 2 costs will be tracked.

MISO Day 2 Costs Deferral Amortization (A14)

The Company based its $4,682,823 pro forma adjustment on a 3 year amortization of its deferred MISO Day 2 costs. The OUCC reduced this amount to $2,997,298 due mostly to use of a 4 year amortization period. The Company has agreed to use a 4 year amortization period and reflected that period, plus a recent updated cost estimate, to arrive at an agreed upon adjustment of $3,063,416.

Labor Adjustments (A16, A17)

The Company adjusted test year long-term and short-term incentive compensation costs to reflect "target" levels of payouts to employees. Target is

The Company proposed to hire apprentice line specialists, electricians, engineers and trainers in advance of the retirements in its workforce to maintain a skilled workforce. The Company also included new employees and programs in its Human Resources and Safety departments to support these initiatives, as well as to generally upgrade the performance in these areas, for a total pro forma amount of $1,719,580. Again, the OUCC agreed with the need to hire apprentices in key operational job categories, but recommended elimination of some internal labor costs, three apprentices being hired to cover anticipated attrition during the course of the apprenticeship programs, and all of the Human Resources/Safety costs. The OUCC supported a pro forma of $1,165,478, $554,102 less than the Company's proposal. In rebuttal, the Company accepted most of these reductions, but preserved certain HR/Safety costs as necessary to address necessary work requirements. The retained HR/Safety costs represent allocated costs consistent with the same HR/Safety costs agreed to in the Vectren-South-Gas Settlement. The final pro forma amount in this area is $1,287,995, which was the Company's position on rebuttal.

Environmental Chemical Expenses/Catalyst Expenses (A24, A25)

The Company uses various chemicals and catalyst in its pollution control processes at its baseload coal plants. Based on projected cost increases driven by increasing compliance standards, catalyst aging and rising chemical costs associated with higher fuel prices, the Company included pro forma adjustments of $2,308,679 for chemicals and $2,540,000 for catalyst. To address volatility associated with these costs, the Company also requested a tracking mechanism.

The OUCC based its recommendations on 2007 contract data and other available 2007 cost projections, and reduced the chemical and catalyst pro formas to $1,114,752 and $1,863,500 respectively, a combined reduction of $1,870,427. The OUCC also rejected the proposed tracking of these O&M costs through the GCRA. On rebuttal, the Company accepted the reduced pro formas, but argued that a tracking mechanism should be approved. The Settlement eliminates the tracker and adopts the OUCC's position related to the costs.

Energy Delivery Maintenance Programs (A33, A34, A35, A36)

Each program is addressed separately below. As a general matter, OUCC witness Soller provided testimonial recommendations that relate to all four maintenance programs based on her prior engineering experience and her extensive dialogue with Company operations personnel over a period of six months. She recommended a written reporting process, update meetings with the OUCC, progress reviews with reference to certain agreed to metrics, and as reflected in the individual program adjustments, a more gradual approach to implementation. These recommendations have been adopted as part of the Settlement.

Substations Inspection Programs (A33)

The Company proposed a program that included periodic breaker inspections, painting, infrared scanning and other maintenance activities at a cost of $1,005,479. Based on the need for more detailed explanation, the OUCC eliminated the breaker inspections, recommended annual infrared scans instead intended to reflect payment of market compensation to employees as part of their overall compensation. The amount of annual incentives will vary above or below target based on the achievement of pre-established metrics that are used to measure performance; this is why such compensation is deemed to be "at risk." The OUCC testimony reduced these incentive compensation adjustments to reflect projected 2006 below target results under the incentive plans. The Company's rebuttal supported use of target levels for ratemaking purposes and for purposes of settlement the OUCC agreed to the pro forma adjustments. This use of target levels of compensation is consistent with the last two Vectren South – Gas rate case settlements.

Additional Employees (A21)

Vectren South proposed the addition of 36 new employees (unrelated to the aging workforce issue) throughout the Company at a cost of $1,671,876. The OUCC reduced this pro forma to $182,679, which reflected only the seven (7) post-test year positions filled as of October 2006. On rebuttal, Vectren South reflected that as of March 2007, 11 of the positions had been filled. Of the remaining 25 proposed new employees, Vectren South agreed to eliminate 13, but continued to support the need for 12 more employees. Vectren South also reflected that with the shut down of Culley Unit 1, and the inability to agree with the union on the reassignment of 12 employees, it would be eliminating the 12 Culley Unit 1 employees at a cost savings of ($840,985). In its case-in-chief, the Company had already reflected non-labor cost savings due to the Culley Unit 1 shut down of ($794,573) (see Adjustment A28). On rebuttal, Vectren South used the Culley Unit 1 labor savings to offset most of the cost of the 12 additional employees the Company proposed to hire, resulting in a remaining net pro forma of $344,190. After further discussing the remaining as yet unhired employees in this category, most of whom are engineers to support increased levels of maintenance activities agreed to in other pro formas, the Company and OUCC reached agreement on inclusion of the cost of 11 employees, resulting in the final Settlement adjustment amount of $217,094. The eleven additional employees are reflected on Pet. Ex. MSH-3S, Adjustment A21-S, p.2.

Aging Workforce—Power Supply (A22)

The Company proposed to hire a number of apprentices in the power supply area to be prepared for the wave of retirements that will hit these key areas in the near future. The apprentice programs are designed to provide trained employees to replace very experienced retirees. The OUCC agreed with this concept, but reduced the pro forma adjustment from $1,392,899 to $835,330 to reflect offsetting cost savings due to retirements and to reduce the number of power plant trainers being added to assist in the apprenticeship process. On rebuttal, the Company agreed to the majority of the OUCC's recommended reductions, but proposed to retain one of the three training clerical employees eliminated by the OUCC to provide necessary assistance to the new training efforts. Thus, the Company reduced its pro forma from $1,392,899 to $909,018. In Settlement, the parties agreed to set the pro forma at $885,351.

Aging Workforce—Energy Delivery (A23)

of semi-annual, and extended the painting cycle from 10 to 15 years, thereby reducing the pro forma to $428,484. On rebuttal, the Company provided further explanation of its breaker inspections, and agreed to the change in frequency related to both infrared scans and painting and reduced the pro forma to $823,192. After further discussion and some changes to the timing of breaker inspections to comply with recently approved NERC reliability standards, the parties agreed to a pro forma amount of $751,068.

Underground Facilities Maintenance (A34)

The Company proposed to engage in regularly scheduled inspections of its downtown Evansville underground network given age and increasing usage at a cost of $354,280. The OUCC agreed with the program but eliminated costs it interpreted to be non-incremental internal labor to arrive at a pro forma of $271,832. After some clarification of the costs of consultants and Company employees involved in the program, the parties agreed on an amount of $327,162. This reflected elimination of internal labor costs which the Company still contends are incremental in nature. Similar disputed internal labor costs were removed in the final Settlement from Training (A20), Reliability Studies (A37) and Meter Reading (A41).

Line Clearance (A35)

The Company proposed adoption of a five year cycle for tree trimming on its distribution and transmission system with a pro forma cost of $1,880,232. The OUCC supported this cycle, but removed $227,232 based on its calculation of the cost of the activity. On rebuttal the Company supported the original cost estimate and explained that it incurred $227,000 of test year expense related to storm damage clearing and not tree trimming, and thus this amount should not be deducted from the pro forma. In Settlement, the Company agreed to the OUCC's reduction and the final pro forma is $1,653,000.

Overhead Facilities Maintenance (A36)

Vectren South proposed a multifaceted program to enhance its inspection and maintenance of overhead facilities, including annual pole inspections, transmission tower painting, inspections of pole guys and grounding, ongoing inspections and work to improve circuit reliability, infrared inspections of circuits and switches, review and improvement of animal guards and frequently failing system components, and the addition of 10 line specialists (other than to replace retirees) to reduce reliance on contract labor which will likely be harder to find as the aging workforce issue impacts contractors. The pro forma amounted to $3,160,733.

The OUCC recommended almost $1.4 million of reductions to this pro forma. These included elimination of additional circuit flyovers and internal labor on several programs, differences in calculation of certain estimates, change in cycle times for infrared inspections, changing the transmission tower painting cycle from 5 to 20 years, and reducing the hiring of 10 new line specialists to three new line specialists.

On rebuttal the Company agreed to reduce the pro forma to $2,682,530, a reduction of $478,195. This change reflected a move to a 10 year cycle on tower painting, a change from annual circuit inspections to every two years, cost reductions to reflect reductions in internal labor, and a proposed hiring of 6 new linemen instead of 10.

The Company and OUCC carefully reviewed each program and negotiated further adjustments to several programs, and reduced the number of new linemen to be hired to 5. The final pro forma is $2,478,136.

Uncollectible Accounts Expense (A40)

The Company based its bad debt expense on a five year historic average percent of revenue (0.38%) while the OUCC proposed use of a more recent three year historic average percent of revenue (0.26%) as of March 2006.

On rebuttal the Company adjusted its pro forma expense from ($372,306) to ($661,248) using a percent of revenue of (0.31%) based upon a 3 year average ended December 2006. In Settlement, the Company agreed to the OUCC's three year average and a pro forma of ($867,578).

Safety Communication Costs (A45)

The Company proposed both a school based safety education program as well as a mass media approach to customer safety education. The OUCC agreed to the school program with a cost of $120,000, but eliminated the remaining costs claiming that they were primarily marketing costs, which reduced the pro forma by $280,000. While the Company defended its entire communication proposal on rebuttal, in the Settlement the Company agreed to the OUCC's positions and a final pro forma of $120,000.

MISO Day 1 Costs (A48)

The Company proposed recovery of its deferred MISO Day 1 Costs using a four year amortization period. The OUCC reduced the pro forma based on a different estimate of the level of authorized deferrals. In Settlement, the OUCC agreed to the Company's pro forma amount.

Property and Risk Insurance (A50)

The Stipulation reflects agreement on the reduction in this expense due to a reduction in insurance premiums that occurred during the pendency of the case. The resulting pro forma adjustment is $301,900.

Claims Expense (A51)

The OUCC reduced the Company's claims expense to exclude recovery of an unpaid claim of over $450,000, and to reflect use of five year amortization of another large claim versus the Company's use of a three year amortization period. This reduced claims expense by $245,000. On rebuttal, the Company explained that the large unpaid claim had recently been paid and that a three year amortization period made sense, especially in light of the Company's heightened risk due to its recent increase in its liability insurance deductible (the reduced premium cost having been passed on to customers in A50). In

Settlement the Company agreed to use a five year amortization period for large claims and reduced its pro forma from its case-in-chief of ($678,892) to ($833,893).

Customer Service Costs (A72)

In response to concerns expressed at the public field hearing and following an extended collaboration between the Company and the OUCC, a number of customer payment method options and complaint handling options were considered. The OUCC and Company have agreed to implement three new customer service options: (1) the installation in the City of Evansville of a centrally located payment kiosk where, with no fee, customers can deposit cash payments in a programmed machine; (2) new payment sites in Evansville and Mt. Vernon where customers can pay gas bills at locations where water bill payments are currently collected; and (3) dedication of 1-2 new employees who will be trained to meet with customers to discuss complaints, thereby providing customers with the opportunity to engage in face to face communication with the Company. Vectren customers will be notified of these options through bill inserts. The cost of these new services, on an allocated basis to Vectren South Electric, is $93,000. This adjustment is set forth on Pet. Ex. No. MSH-3S, Adjustment A72. The allocated cost of these same new services was included in the Vectren South-Gas Settlement.

Asset Charge (A57)

As reflected in testimony, the parties have agreed on the calculation methodology used to determine this cost (see Pet. Ex. No. MSH-3S, Adjustment 57). The calculation using the agreed upon 10.4% ROE has been performed and is reflected in Appendix C.

Depreciation (A58)

The Company agreed to the OUCC's recommendation to change the depreciation rate for the Fabric Filter installation at Culley Unit 3, changing its depreciation expense pro forma from $161,266 to ($59,234). In rebuttal testimony and in settlement discussions the Company and OUCC discussed and reviewed the data used by the Company to support its study, and thereby addressed the OUCC's concerns.

Income Taxes, IURT Taxes (A60, A63 and A64)

There are no differences between the parties on these items which have been determined based upon the settlement amounts in this case.

3. Return on Equity (ROE) Test.

The parties have agreed that the Company's proposed ROE test will not be adopted as a replacement for the existing Net Operating (NOI) test. However, consistent with past adjustments to the Company's level of authorized NOI to accommodate recovery of costs related to its approved NOx and Multi-Pollutant environmental projects, the parties agree that the Company's authorized NOI for purposes of the NOI test should be similarly adjusted in the future to allow the Company to retain its recovery of costs associated with approved Senate Bill 29 projects (Ind. Code §8-1-8.8 et. seq.), as well as for the agreed upon NOI adjustment associated with the opportunity to retain a share of Non-Firm Wholesale Power Margins (WPM) as described below.

The parties have also agreed that within 30 days of an order in this proceeding, the OUCC will invite the Company and IG, as well as other interested stakeholders, other utilities and the Staff to discuss the relative merits of the NOI earnings test versus an ROE earnings test. The OUCC and/or Company may ultimately file a petition related to the earnings test following these discussions.

4. Generation Cost and Revenue Adjustment (GCRA).

The parties have agreed that the GCRA will be renamed the Reliability Cost and Revenue Adjustment (RCRA) and that changes from the base rate amount of Direct Load Control Billing Credits will be tracked separately under a DSM Adjustment (DSMA). The parties further agree that the Company's proposal to track changes in chemical and catalyst costs will be withdrawn. Therefore, the RCRA will now be used to adjust the Company's rates for the following items:

1. Non-Firm Wholesale Power Margins (WPM)
2. Municipal Wholesale Margins
3. Environmental Emission Allowance (EEA) Credits
4. Interruptible Sales billing credits

5. Purchased Power Non-Fuel Costs

Two of these items, Municipal Wholesale Margins and EEA credits, represent pass through of cost reductions to customers. The Company will provide 100% of the margins from its Municipal Wholesale contracts to customers (following an order in this case) during the remaining duration of these contracts in 2007 and 2008, including sales to municipal suppliers during this period as described in Jochum's rebuttal testimony. The Company will also credit customers for 100% of the market value of all EEAs it uses to back its WPM sales. The EEA credits reflect use of SO2 and NOx allowances, and at the time required for compliance in the future, this adjustment will also reflect the value of mercury allowances.

The Company will file the RCRA semi-annually (every 6 months). The first 6 months of estimated credits from municipal wholesale sales and EEA credits will be filed at the same time new rates from this proceeding go into effect. In each new tracker filing, the Company will include a forecast of the amount of future RCRA filings.

The sharing of WPM results may also provide a credit or a charge to customers depending upon the level of such margins achieved by the Company compared to the base rate revenue requirement credit of $10.5 million. The WPM sharing mechanism is described further below.

To the extent the Company incurs purchased power demand costs different from its base level of costs, those differences will be tracked under the RCRA. Also, to the extent the Company incurs Interruptible Sales billing credits different from the base level of such billing credits, those differences will be tracked under the RCRA. Currently, the Company provides a billing credit to one large interruptible customer.

5. Non-Firm Wholesale Power Margins (WPM).

In its case-in-chief the Company proposed to follow the approved Duke Indiana model and share WPM results 50/50 with customers. The Company "embedded" as a credit to its revenue requirement in this case $10.5 million, the pro forma amount of WPM. Under the proposal, the Company and customers share equally in results above and below that $10.5 million target. The parties have reached agreement that the Company should retain an incentive to maximize WPM results, and that risk and reward in this area should be shared. Therefore, under the Settlement, this 50/50 sharing proposal has been adopted, with the customer share of WPM to flow through the RCRA. The parties recognized that the Company's current NOI under earnings bank of ($202 million) will be eliminated upon receipt of an order in this case, thereby potentially reducing the Company's opportunity to retain its potential share of WPM proceeds. Thus, the incentive opportunity may be effectively lost and customers could receive both their 50% share of additional WPM proceeds as well as the Company's share of WPM proceeds. To address this particular set of circumstances in terms of the loss of a large historic under earnings bank, and recognizing the large capital needs, environmental risks and other challenges facing the Company, which is a very small electric utility, the parties have agreed that for four years (16 FAC quarters) following the order herein, the Company will be allowed up to a $3 million increase to its authorized NOI for purposes of calculating the NOI earnings test, but only to the extent that the Company's share of WPM proceeds recorded on the Company's books have created its over earning status. This incremental amount provides the ability to retain the 50% share WPM proceeds.

6. MISO Cost and Revenue Adjustment (MCRA).

The parties have reached agreement on the tracking of changes in the base expense amounts of non-fuel MISO costs, costs associated with MISO Day 1 and Day 2 which are not already recovered via the FAC.

In this case, the Company had also proposed to recover its costs associated with future investments in transmission infrastructure in furtherance of FERC's policy to support increased investment in the transmission grid. On rebuttal, the Company divided its transmission investment into three distinct categories: (1) existing investment included in retail rate base, (2) Regional Expansion Criteria and Benefit Process (RECB) investment, and (3) non-RECB MISO reviewed and approved investment.

With respect to these 3 categories of investment, the parties have agreed as follows: current investment will remain included in retail rate base. RECB costs will be tracked, and non-RECB costs will not be tracked. RECB costs will be charged to the Company under MISO Schedule 26—this will include charges related to the Company's own RECB projects as well as its allocation of costs related to other third party RECB projects. Through Schedule 26, the Company will receive partial cost recovery for its projects from other transmission owners in the MISO footprint on an allocated basis. The Company will be authorized to retain the allocated portion of cost recovery from native load customers as calculated under Schedule 26 as well as the revenues received from other MISO transmission owners under Schedule 26—all such Schedule 26 recoveries shall be treated as non-jurisdictional and outside the earnings test to allow the Company to recover its costs. The Company's RECB projects will not be included in retail rate base.

The Company will also invest in other reliability projects that do not qualify for RECB treatment, but will be MISO approved (non-RECB projects). The Company has agreed to withdraw its request to recover costs related to such projects between rate cases under its proposed MISO Transmission Component of the MCRA, and has also dropped its alternative request for post-in service AFUDC and deferred depreciation for such projects. With respect to ratemaking related to MISO tariff/costs, nothing in the Settlement should be interpreted to prevent the Company from pursuing cost recovery or different ratemaking treatment in later proceedings based upon newly adopted statutes or orders issued by the FERC or IURC. In future proceedings regarding MISO tariff/cost recovery, nothing in this Settlement will be interpreted to prevent the parties from taking any position with respect to cost recovery proposals.

A representative level of transmission revenues has been included as revenue credits in the Settlement revenue requirements. The parties have agreed to track actual differences from these base rate levels during the first year after the implementation of new rates in this proceeding. Prior to the end of the first year, the parties will meet to review available data regarding the Company's actual transmission revenues. After review and discussion, the parties will present to the Commission a proposal regarding the future tracking of actual differences from the transmission revenues credited in base rates. That proposal will address the Company's ability to retain the portion of transmission revenues related to its non-RECB transmission investment not otherwise recovered from retail customers. Absent agreement of the parties, any party may file a tracking proposal and revenues will be deferred until further order of the Commission.

The Company will file the MCRA semi-annually (every 6 months). In each new tracker filing, the Company will include a forecast of the amount of future MCRA filings.

7. Future Rate Case and Reporting Commitments.

The parties agree that the Company will file a base rate case no later that December 31, 2012. During this interim period, the Company will provide reports to the OUCC regarding certain system metrics and progress on maintenance programs. The framework related to the timing and contents of such reports is set forth in Appendix D. The various cost recovery trackers agreed to in this Settlement shall remain in effect until a final order in the next rate case. Should the parties reach mutual agreement to extend the deadline for the next rate case, they will inform the Commission of the decision to extend the filing date and the basis thereof prior to December 31, 2012. When Vectren South files its next base rate case, the Company will file two cost of service studies: one using 4CP to allocate all operating costs, and the other will be the same except for using 12CP to allocate jurisdictional transmission costs. The Company may recommend use of either approach.

8. Cost of Service/Rate Design.

For purposes of settlement only, the Parties have agreed to maintain the existing cost of service allocations, including transmission and generation function allocations based on a 4 coincident peak (4 cp) methodology, and to reflect a 25% subsidy reduction. The revenue responsibility for each rate schedule has been established based on the settlement cost of service. The cost of service allocation reflects the Company's special contract with PPG Industries which has been filed with the Commission pursuant to a separate Settlement Agreement. To the extent the PPG Settlement is not approved, the Company would modify its cost of service study to reflect the implications of continuing to serve PPG at the new base rates.

The settlement rates and charges are reflected in the Revenue Proof to be filed with testimony. Except for Residential Rate A, the Settlement revenue increase for each rate schedule was distributed among the rate schedule's Customer Facilities Charge, Demand Charge (where applicable), and Energy Charges rate blocks in the same manner as in the Company's case-in-chief, continuing the objective of having the bill impacts to any customer be no more than approximately two times the overall rate schedule increase. For the Residential Rate A, the Customer Facilities Charges was established at $5.50 and the

Energy Charge rate blocks were increased from present rates on an equal percentage basis to recover the remaining rate class increase.

9. Tariff

A Settlement Tariff will be filed in testimony. The settlement tariff includes a number of changes as proposed by the Company in its case-in-chief as well as updated tariff sheets reflecting tariff changes approved by the Commission after the initiation of this rate proceeding. The tariff changes are summarized below.

Rate Schedule Changes

1. Rate and Charges revisions to reflect the settlement rates and charges.
2. Rate Schedule revisions, deletions and additions including;
    a. Addition of a rate step to Rate EH (Home Heating).
    b. Modified Applicability section of Rate B (Water Heating) to clarify eligibility.
    c. Splitting Rate GS (General Service) into two Rate Schedules - Rate SGS (Small General Service) and Rate DGS (Demand General Service) and revising both rate structures, including revising the Determination of Billing Demand section for DGS.
    d. A revision to the Determination of Billing Demand for Rate OSS (Off Season Service).

e. Revisions to Rate LP (Large Power) to :

i. Eliminate grandfathering of former Rate PP-2 customers.

ii. A revision to the Minimum Bill section.

iii. A revision to the Determination of Billing Demand Section.

iv. Modified Contract section to require a minimum three-year initial term

f. Revised Rate BAMP (Backup, Auxiliary, and Maintenance Power Services) such that the Maintenance Capacity and Energy Charges will refer to the LP rates.

g. Elimination of Street Lighting Rate Schedules SL-4 and SL-6.

3. The addition of Availability sections and the additions of Appendices and Riders sections to each Rate Schedule to more readily identify Adjustments and available Riders applicable to customers in each Rate Schedule.

Rider Changes

4. The addition of Rider IC (Interruptible Contract Rider) and Rider IO (Interruptible Option Rider) to offer interruptible service to customers.

5. The addition of Rider ED (Economic Development Rider) and Rider AD (Area Development Rider) to be available to qualifying customers new to Vectren South's service area or with increased loads at existing locations.

6. The elimination of Rider HLF-1 and the closing to new customers of Rider LP-1 (Energy Incentive Riders) which are being replaced with the two new economic development Riders.

7. The addition of Rider DLC (Direct Load Control Rider) to reflect credits applicable to customers participating in the Company's Summer Cycler DLC program .

Appendices Changes

8. The revision of Appendix B (Demand-Side Management Adjustment, the "DSMA") from a DSM lost revenue tracker, to a Direct Load Control credit tracker.

9. The elimination of Appendix C – Clean Air Act Amendment Adjustment, by rolling the credits tracked by it into Appendix J, the RCRA.

10. The addition of language providing more detailed descriptions for the recurring charges already reflected in Appendix D, Other Charges.

11. The eliminations of NOx-related Appendix E (Qualified Pollution Control Property – Construction Cost Adjustment) and Appendix F (Qualified Pollution Control Property – Operating Expense Adjustment) by rolling the costs recovered via these trackers into base rates.

12. The addition of Appendix I (MISO Cost and Revenue Adjustment, the "MCRA") to track certain costs and revenues related to MISO.

13. The addition of Appendix J (Reliability Cost and Revenue Adjustment, the "RCRA") to track certain costs and revenues related to the reliability of Vectren South's power supply portfolio.

Terms and Conditions Changes

14. The addition of item a.6 to Rule 1, Application of Rates, to clarify that averages may not be avoided by switching service from the name of a person still residing at the premise.

15. The revision of language describing the Equal Payment Plan in Rule 10d.

16. The addition of details regarding Vectren South's Curtailment Procedures in Rule 19.

17. The elimination of Rule 21 – Utility Residential Weatherization Program.

Other Miscellaneous Tariff Changes

18. Revision to the tariff page numbering system to facilitate future updates.

19. The addition of a Definitions Section to contain definitions of words and terms that reoccur in the Tariff. The defined terms are shown with initial capital letters when they later appear in the Tariff.

20. Other minor changes in the nature of housekeeping throughout the Tariff.

<u>Tariff Sheets Revisions Approved by the Commission Subsequent to Case-In-Chief</u>

21. Addition of Rate S (Emergency Notification Sirens).

22. Additions of Multi-pollutant trackers—Appendix G (QPCP-CC2) and Appendix H (QPCP-OE2).

23. Updates to Rate CSP (Cogeneration and Small Power Production) and Rider NM (Net Metering) to reflect changes required by the Interconnection Standards approved by the Commission.

10. Request for Prompt Approval by the Commission.

The parties acknowledge that a significant motivation for the Company to enter into the Settlement is the expectation that an order will be issued promptly by the Commission authorizing increases in its rates and charges. The parties have spent many months reviewing data and negotiating this Settlement in an effort to eliminate time consuming and costly litigation. In particular, the OUCC and Company have reviewed the maintenance programs, and have worked together on the metrics and reporting structure included in the Settlement. The resulting Settlement has reduced the Company's filed request for a rate increase and modified its other requested cost recovery mechanisms. Under these circumstances, the parties ask that their request for prompt approval be seriously considered and acted upon.

11. Stipulation Effect, Scope and Approval.

The parties acknowledge and agree as follows:

(a) The Stipulation is conditioned upon and subject to its acceptance and approval by the Commission in its entirety without any change or condition that is unacceptable to any party. Each term of the Stipulation is in consideration and support of each and every other term.

(b) The Stipulation is the result of compromise in the settlement process and neither the making of the Stipulation nor any of its provisions shall constitute an admission or waiver by any party in any other proceeding. The Stipulation shall not be used as precedent in any other proceeding or for any other purpose except to the extent provided for herein or to the extent necessary to implement or enforce its terms.

(c) The evidence to be submitted in support of the Stipulation constitutes substantial evidence sufficient to support the Stipulation and provides an adequate evidentiary basis upon which the Commission can make any findings of fact and conclusions of law necessary for the approval of the Stipulation.

(d) The communications and discussions and materials produced and exchanged during the negotiation of the Stipulation relate to offers of settlement and shall be privileged and confidential.

(e) The undersigned represent and agreed that they are fully authorized to execute the Stipulation on behalf of their designated clients who will be bound thereby.

(f) The parties will either support or not oppose on rehearing, reconsideration and/or appeal, an IURC Order accepting and approving this Stipulation in accordance with its terms.

ACCEPTED and AGREED this 20 th day of April, 2007.

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

By: ______________________

Jeffrey M. Reed
Assistant Consumer Counselor

VECTREN ENERGY DELIVERY OF INDIANA, INC. a/k/a SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

By: Robert E. Heidorn DWM

Robert E. Heidorn

Intervenor Industrial Group

By: ______________________
Timothy L. Stewart

INDS01 DWM STIPULATION AND SETTLEMENT AGREEMENT.DOC

VECTREN SOUTH
ELECTRIC TARIFF
ACTUAL AND PRO FORMA STATEMENT OF OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Line No.	Description	Actual Per Books	Pro Forma Adjustments Increases (Decreases)	Ref	Pro Forma Results Based on Current Rates	Pro Forma Adjustments Increases (Decreases)	Ref	Pro Forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
	Operating Revenues							
1	Electric Revenue	$ 434,583,374			$ 412,659,811	$ 67,255,394	A65-S	$ 479,915,205
2	Normal Weather		(1,355,531)	A01				
3	Annualized Days of Service		1,713,062	A02				
4	Customer Count		784,530	A03				
5	Large Customer Changes		711,861	A04				
6	Miscellaneous Revenue		178,857	A05				
7	Unbilled Revenue		(1,455,828)	A06				
8	Cost of Fuel		13,695,641	A07				
9	Wholesale Power Marketing Revenue		(10,200,159)	A08				
10	Municipal Customer Revenue		(25,911,843)	A09				
11	DSM Lost Margin Revenue		(84,153)	A10				
12	Total	434,583,374	(21,923,563)		412,659,811	67,255,394		479,915,205
13	**Fuel and Purchased Power**	153,068,787			158,632,230			158,632,230
14	Normal Weather		(336,977)	A01				
15	Annualized Days of Service		885,661	A02				
16	Customer Count		200,633	A03				
17	Large Customer Changes		(207,375)	A04				
18	Cost of Fuel		13,494,389	A07				
19	Wholesale Power Marketing Fuel Expenses		(4,678,890)	A08				
20	Municipal Customer Fuel Expenses		(13,241,883)	A09				
21	Fuel Handling Expenses		-	A11				
22	Purchased Power Demand Costs		3,715,500	A12				
23	Ongoing MISO Day 2 Costs		2,668,969	A13				
24	MISO Day 2 Costs Deferral Amortization		3,063,416	A14				
25		153,068,787	5,563,443		158,632,230	-		158,632,230
26	Gross Margin	$ 281,514,588	$ (27,487,006)		$ 254,027,582	$ 67,255,394		$ 321,282,976

VECTREN SOUTH
ELECTRIC TARIFF
ACTUAL AND PRO FORMA STATEMENT OF OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Line No.	Description	Actual Per Books	Pro Forma Adjustments Increases (Decreases)	Ref	Pro Forma Results Based on Current Rates	Pro Forma Adjustments Increases (Decreases)	Ref	Pro Forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
	Operation and Maintenance Expenses							
27	Operations and Maintenance Expenses	$ 96,293,286			$ 122,424,250			122,673,095
28	**Labor and Labor Related Costs**							
29	Labor Adjustments for Existing Headcount		2,960,133	A15				
30	Labor-Related Costs		617,289	A16				
31	Other Compensation		311,785	A17				
32	Pension Expense		341,067	A18				
33	Postretirement Medical Expense		(294,807)	A19				
34	Training Expense		141,468	A20-S				
35	Additional Employees		217,094	A21-S				
36	**Aging Workforce Related Costs**							
37	Power Supply		885,351	A22				
38	Energy Delivery		1,287,995	A23				
39	**Operation and Maintenance Programs**							
40	Environmental Chemical Expenses		1,114,752	A24				
41	Catalyst Expenses		1,863,500	A25				
42	Ash Disposal Costs		1,500,000	A26				
43	By Product Sales		984,850	A27				
44	Culley Unit 1 Expense Reduction		(794,573)	A28				
45	Turbine Maintenance		3,359,950	A29				
46	Flue Gas Desulphurization Structural Maintenance		1,075,000	A30				
47	Wholesale Power Marketing Trading Expenses		(278,904)	A31				
48	Boiler Outage and Maintenance		1,078,855	A32				
49	Substation Inspection Programs		751,068	A33-S				
50	Underground Facilities Maintenance		327,162	A34-S				
51	Line Clearance		1,653,000	A35-S				
52	Overhead Facilities Maintenance		2,478,136	A36-S				
53	Reliability Studies and Planning		93,750	A37-S				
54	Ongoing Demand Side Management Programs		947,582	A38				
55	Ongoing MISO Day 1 Administrative Costs		1,342,877	A39				
56	Uncollectible Accounts Expense		(867,578)	A40-S				
57	Meter Reading Costs		29,133	A41-S				
58	Miscellaneous Billing Costs		20,715	A42				
59	Sales and Marketing Costs		93,000	A43				
60	Contact Center Costs		157,036	A44				
61	Safety Communication Costs		120,000	A45-S				
62	Information Technology Costs		180,346	A46				
63	**Amortization of Deferrals**							
64	New Source Review Litigation Costs		985,111	A47				
65	MISO Day 1 Costs		1,501,694	A48				
66	Rate Case Expense		377,333	A49				
67	**Other Costs/Adjustments**							
68	Property and Risk Insurance		301,900	A50				
69	Claims Expenses		(833,893)	A51-S				
70	Other Cost Reductions		(99,680)	A52				
71	Changes in Cost Allocations		(32,771)	A53				
72	Asset Management Program Costs		103,480	A54				
73	Asset Management Program Savings		(35,923)	A55				
74	Customer Service Costs		93,000	A72				
75	Going Level Uncollectible Accounts					174,864	A66	
76	IURC Fee		73,681	A56		73,981	A67	
77		96,293,286	26,130,964		122,424,250	248,845		122,673,095
78	Asset Charge	8,037,136	521,368	A57-S	8,558,504			8,558,504
79	Total Operations and Maintenance	$ 104,330,422	$ 26,652,332		$ 130,982,754	$ 248,845		$ 131,231,599

VECTREN SOUTH
ELECTRIC TARIFF
ACTUAL AND PRO FORMA STATEMENT OF OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Line No.	Description	Actual Per Books	Pro Forma Adjustments Increases (Decreases)	Ref	Pro Forma Results Based on Current Rates	Pro Forma Adjustments Increases (Decreases)	Ref	Pro Forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
80	Depreciation and Amortization	$ 58,788,501	(59,234)	A58	$ 64,274,381			64,274,381
81			5,545,114	A59				
82	Total Depreciation and Amortization	58,788,501	5,485,880		64,274,381	-		64,274,381
	Taxes							
83	Income Taxes (Federal and State)	33,129,594	(5,341,392)	A60	7,675,600	5,695,557	A68	34,501,310
84			175	A61		-	A69	
85			(20,112,777)	A62		21,130,153	A70	
86	Other Taxes (IURT and Property Tax)	12,381,146	621,677	A63	13,936,359	939,127	A71	14,875,486
87			933,537	A64				
88	Total Taxes	45,510,740	(23,898,781)		21,611,959	27,764,837		49,376,796
89	Total Operating Expenses	208,629,663	8,239,431		216,869,095	28,013,682		244,882,777
90	Net Operating Income	$ 72,884,924	$ (35,726,437)		$ 37,158,487	$ 39,241,712		$ 76,400,199

VECTREN SOUTH
ELECTRIC TARIFF
Calculation of Proposed Revenue Increase
Based on Pro Forma Operating Results
Original Cost Rate Base Estimated at October 31, 2006

Revenue Increase Based on Net Original Cost Rate Base

1	Net Original Cost Rate Base	$	1,043,718,562
2	Rate of Return		7.32%
3	Required Net Operating Income		76,400,199
4	Pro Forma Net Operating Income		37,158,487
5	Increase in Net Operating Income (NOI Shortfall)		39,241,712
6	Effective Incremental Revenue/NOI Conversion Factor		58.3%
7	Increase in Revenue Requirement (Based on Net Original Cost Rate Base) (Line 5 / Line 6)	$	67,255,394

8	One		1.000000			
9	Less: IURC Fee		0.001100			
10	Less: Bad Debt		0.002600			
11	One Less IURC Fee and IURT			0.996300		
12	One	1.000000				
13	Less: Bad Debt	0.002600				
14	Taxable Adjusted IURT		0.997400			
15	IURT Rate		0.014000			
16	Adjusted IURT			0.013964		
17	One	1.000000				
18	Less: Bad Debt	0.002600				
19	Less: IURC Fee	0.001100				
20	Taxable Adjusted Gross Income Tax		0.996300			
21	Adjusted Gross Income Tax Rate		0.085000			
22	Adjusted Gross Income Tax			0.084686		
23	Kentucky Apportionment		0.000538			
24	Kentucky State Income Tax Rate		0.070000			
25	Effective Kentucky Income Tax Rate			0.000038		
26	Kentucky Coal Tax Credit Effect			-0.000038		
27	Line 11 less line 22 less line 25 less line 26				0.897651	
28	One			1.000000		
29	Less: Federal Income Tax Rate			0.350000		
30	One Less Federal Income Tax Rate				0.650000	
31	Effective Incremental Revenue/NOI Conversion Factor (line 27 times line 30)					58.3%

VECTREN SOUTH
ELECTRIC TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME

Statement of Electric Property
Original Cost Rate Base at October 31, 2006

Line No.	Activity (FERC) No.	Description	Electric Plant Per Books at October 31, 2006	Adjustments and Eliminations	As Adjusted Pro Forma Rate Base at October 31, 2006
		Utility Plant			
1	101	In Service - Unitized	$ 1,312,023,679	$ -	$ 1,312,023,679
2	105	Property Held for Future Use	3,163,409	(3,163,409)	$ -
3	106	Completed Const. Not Classified	421,191,296	-	$ 421,191,296
4	106	Addition of Fabric Filter at Culley Unit 3 (February 2007)	-	50,519,592	$ 50,519,592
5	107	Const. Work in Progress	66,962,032	(66,962,032)	$ -
6			1,803,340,416	(19,605,849)	$ 1,783,734,567
		Accumulated Depreciation			
7	108	Utility Plant	(812,808,720)	-	$ (812,808,720)
8		Net Utility Plant	990,531,696	(19,605,849)	$ 970,925,847
		Material & Supplies (13 Month Average)			
9	154	Utility Material & Supplies	22,167,395		$ 22,167,395
10	163	Stores Expense	3,101,884		$ 3,101,884
11	151	Fuel Stock	17,600,522		$ 17,600,522
12	158	Allowance Inventory	117,419		$ 117,419
13		Total Material & Supplies	42,987,220		$ 42,987,220
14	182	DSM - Post 1994 Regulatory Asset	27,611,703		$ 27,611,703
15	182	DSM - Pre 1994 Regulatory Asset	1,543,877		$ 1,543,877
16	182	MISO Day 2 Startup Costs	649,916		$ 649,916
17		TOTAL	$ 1,063,324,412	$ (19,605,849)	$ 1,043,718,562

VECTREN SOUTH
ELECTRIC TARIFF
Capital Structure and Cost of Capital
Twelve months ending March 31, 2006

Line No.	Type of Capital		Amount ($000's)	Percent	Cost	WCOC
1	**Long-Term Debt**					
2	Publicly Held	$	228,165	19.54%		
3	Notes to VUHI		223,182	19.11%		
4	Total Long-Term Debt	$	451,347	38.65%	6.04%	2.33%
5	**Common Equity**					
6	Common Stock	$	273,263	23.40%		
7	Retained Earnings		274,999	23.55%		
8	Accumulated Comprehensive Income		1,246	0.11%		
9	Common Shareholder's Equity	$	549,508	47.05%	10.40%	4.89%
10	**Investor Provided Capital**	$	1,000,855	85.70%		7.23%
11	**Customer Deposits**	$	5,601	0.48%	5.39%	0.03%
12	**Cost Free Capital**					
13	Deferred Taxes	$	138,730	11.88%		
14	Customer Advances for Construction		2,211	0.19%		
15	SFAS 106		11,536	0.99%		
16	Total Cost Free Capital	$	152,477	13.06%	0.00%	0.00%
17	**Job Development Investment Tax Credit (Post-1971)**	$	8,920	0.76%	8.43%	0.06%
18	**Total Capitalization**	$	1,167,853	100.00%		
19	Rate of Return					7.32%

<u>Investor Provided Capital</u>

Line No.			Amount ($000's)	Percent	Cost	WCOC
20	Long-Term Debt	$	451,347	45.10%	6.04%	2.72%
21	Common Equity		549,508	54.90%	10.40%	5.71%
22	Total Capitalization	$	1,000,855	100.00%		8.43%

<u>Interest Synchronization</u>

Line No.		Percent	Cost	Weighted Cost
23	Long-term Debt	38.65%	6.04%	2.33%
24	Customer Deposits	0.48%	5.39%	0.03%
25	Interest Component of ITC	0.76%	6.04%	0.05%
26	Total			2.41%
27	Original Cost Rate Base			$ 1,043,718,562
28	Synchronized Interest Expense			$ 25,153,617

VECTREN SOUTH
ELECTRIC TARIFF
SETTLEMENT SCHEDULE OF PRO FORMA ADJUSTMENTS

Line No.	Description	AS ORIGINALLY FILED Pro Forma Adjustments Increases (Decreases)	Ref	OUCC FILED Pro Forma Adjustments Increases (Decreases)	REBUTTAL FILED Pro Forma Adjustments Increases (Decreases)	Ref	SETTLEMENT Pro Forma Adjustments Increases (Decreases)	Ref	Line No.
	A	B	C	D	E	F	G	H	
	Operating Revenues								
1	Electric Revenue								1
2	Normal Weather	$ (1,355,531)	A01	$ (1,355,531)	$ (1,355,531)	A01	$ (1,355,531)	A01	2
3	Annualized Days of Service	$ 1,713,062	A02	$ 1,713,062	$ 1,713,062	A02	$ 1,713,062	A02	3
4	Customer Count	$ 784,530	A03	$ 784,530	$ 784,530	A03	$ 784,530	A03	4
5	Large Customer Changes	$ 711,861	A04	$ 711,861	$ 711,861	A04	$ 711,861	A04	5
6	Miscellaneous Revenue	$ 178,857	A05	$ 178,857	$ 178,857	A05	$ 178,857	A05	6
7	Unbilled Revenue	$ (1,455,828)	A06	$ (1,455,828)	$ (1,455,828)	A06	$ (1,455,828)	A06	7
8	Cost of Fuel	$ 13,695,641	A07	$ 13,695,641	$ 13,695,641	A07	$ 13,695,641	A07	8
9	Wholesale Power Marketing Revenue	$ (10,200,159)	A08	$ (10,200,159)	$ (10,200,159)	A08	$ (10,200,159)	A08	9
10	Municipal Customer Revenue	$ (25,911,843)	A09	$ (25,911,843)	$ (25,911,843)	A09	$ (25,911,843)	A09	10
11	DSM Lost Margin Revenue	$ (84,153)	A10	$ (84,153)	$ (84,153)	A10	$ (84,153)	A10	11
12	Total	(21,923,563)		(21,923,563)	(21,923,563)		(21,923,563)		12
13	**Fuel and Purchased Power**								13
14	Normal Weather	$ (336,977)	A01	$ (336,977)	$ (336,977)	A01	$ (336,977)	A01	14
15	Annualized Days of Service	$ 885,661	A02	$ 885,661	$ 885,661	A02	$ 885,661	A02	15
16	Customer Count	$ 200,633	A03	$ 200,633	$ 200,633	A03	$ 200,633	A03	16
17	Large Customer Changes	$ (207,375)	A04	$ (207,375)	$ (207,375)	A04	$ (207,375)	A04	17
18	Cost of Fuel	$ 13,494,389	A07	$ 13,494,389	$ 13,494,389	A07	$ 13,494,389	A07	18
19	Wholesale Power Marketing Fuel Expenses	$ (4,678,890)	A08	$ (4,678,890)	$ (4,678,890)	A08	$ (4,678,890)	A08	19
20	Municipal Customer Fuel Expenses	$ (13,241,883)	A09	$ (13,241,883)	$ (13,241,883)	A09	$ (13,241,883)	A09	20
21	Fuel Handling Expenses	$ 332,391	A11	$ -	$ -	A11-R	$ -	A11	21
22	Purchased Power Demand Costs	$ 3,715,500	A12	$ 3,715,500	$ 3,715,500	A12	$ 3,715,500	A12	22
23	Ongoing MISO Day 2 Costs	$ 5,420,266	A13	$ 2,668,969	$ 2,668,969	A13-R	$ 2,668,969	A13	23
24	MISO Day 2 Costs Deferral Amortization	$ 4,682,823	A14	$ 2,997,298	$ 3,063,416	A14-R	$ 3,063,416	A14	24
25		10,266,538		5,497,325	5,563,443		5,563,443		25
26	Gross Margin	$ (32,190,101)		$ (27,420,888)	$ (27,487,006)		$ (27,487,006)		26

VECTREN SOUTH
ELECTRIC TARIFF
SETTLEMENT SCHEDULE OF PRO FORMA ADJUSTMENTS

Line No.	Description	AS ORIGINALLY FILED Pro Forma Adjustments Increases (Decreases)	Ref	OUCC FILED Pro Forma Adjustments Increases (Decreases)	REBUTTAL FILED Pro Forma Adjustments Increases (Decreases)	Ref	SETTLEMENT Pro Forma Adjustments Increases (Decreases)	Ref	Line No.
	A	B	C	D	E	F	G	H	
	Operation and Maintenance Expenses								
27	Operations and Maintenance Expenses								27
28	**Labor and Labor Related Costs**								28
29	Labor Adjustments for Existing Headcount	$ 2,960,133	A15	$ 2,968,911	$ 2,960,133	A15	$ 2,960,133	A15	29
30	Labor-Related Costs	$ 617,289	A16	$ 148,786	$ 617,289	A16	$ 617,289	A16	30
31	Other Compensation	$ 311,785	A17	$ (492,277)	$ 311,785	A17	$ 311,785	A17	31
32	Pension Expense	$ 341,067	A18	$ 341,067	$ 341,067	A18	$ 341,067	A18	32
33	Postretirement Medical Expense	$ (294,807)	A19	$ (294,807)	$ (294,807)	A19	$ (294,807)	A19	33
34	Training Expense	$ 145,403	A20	$ 133,360	$ 144,270	A20-R	$ 141,468	A20-S	34
35	Additional Employees	$ 1,671,876	A21	$ 182,679	$ 344,190	A21-R	$ 217,094	A21-S	35
36	**Aging Workforce Related Costs**								36
37	Power Supply	$ 1,392,899	A22	$ 835,330	$ 909,018	A22-R	$ 885,351	A22-S	37
38	Energy Delivery	$ 1,719,580	A23	$ 1,165,478	$ 1,287,995	A23-R	$ 1,287,995	A23	38
39	**Operation and Maintenance Programs**								39
40	Environmental Chemical Expenses	$ 2,308,679	A24	$ 1,114,752	$ 1,114,752	A24-R	$ 1,114,752	A24	40
41	Catalyst Expenses	$ 2,540,000	A25	$ 1,863,500	$ 1,863,500	A25-R	$ 1,863,500	A25	41
42	Ash Disposal Costs	$ 1,500,000	A26	$ 1,500,000	$ 1,500,000	A26	$ 1,500,000	A26	42
43	By Product Sales	$ 984,850	A27	$ 984,850	$ 984,850	A27	$ 984,850	A27	43
44	Culley Unit 1 Expense Reduction	$ (794,573)	A28	$ (794,573)	$ (794,573)	A28	$ (794,573)	A28	44
45	Turbine Maintenance	$ 3,359,950	A29	$ 3,359,950	$ 3,359,950	A29	$ 3,359,950	A29	45
46	Flue Gas Desulphurization Structural Maintenance	$ 1,075,000	A30	$ 1,075,000	$ 1,075,000	A30	$ 1,075,000	A30	46
47	Wholesale Power Marketing Trading Expenses	$ (278,904)	A31	$ (278,904)	$ (278,904)	A31	$ (278,904)	A31	47
48	Boiler Outage and Maintenance	$ 1,078,855	A32	$ 970,778	$ 1,078,855	A32	$ 1,078,855	A32	48
49	Substation Inspection Programs	$ 1,005,479	A33	$ 428,484	$ 823,192	A33-R	$ 751,068	A33-S	49
50	Underground Facilities Maintenance	$ 354,280	A34	$ 271,832	$ 342,037	A34-R	$ 327,162	A34-S	50
51	Line Clearance	$ 1,880,232	A35	$ 1,653,000	$ 1,880,232	A35	$ 1,653,000	A35-S	51
52	Overhead Facilities Maintenance	$ 3,160,733	A36	$ 1,773,028	$ 2,682,538	A36-R	$ 2,478,136	A36-S	52
53	Reliability Studies and Planning	$ 102,500	A37	$ 85,000	$ 102,500	A37	$ 93,750	A37-S	53
54	Ongoing Demand Side Management Programs	$ 947,582	A38	$ 947,582	$ 947,582	A38	$ 947,582	A38	54
55	Ongoing MISO Day 1 Administrative Costs	$ 1,342,877	A39	$ 1,342,877	$ 1,342,877	A39	$ 1,342,877	A39	55
56	Uncollectible Accounts Expense	$ (372,386)	A40	$ (867,578)	$ (661,248)	A40-R	$ (867,578)	A40-S	56
57	Meter Reading Costs	$ 39,467	A41	$ -	$ 39,467	A41	$ 29,133	A41-S	57
58	Miscellaneous Billing Costs	$ 20,715	A42	$ 20,715	$ 20,715	A42	$ 20,715	A42	58
59	Sales and Marketing Costs	$ 95,090	A43	$ 95,090	$ 93,000	A43	$ 93,000	A43	59
60	Contact Center Costs	$ 157,036	A44	$ 157,036	$ 157,036	A44	$ 157,036	A44	60
61	Safety Communication Costs	$ 400,000	A45	$ 120,000	$ 400,000	A45	$ 120,000	A45-S	61
62	Information Technology Costs	$ 180,346	A46	$ 180,346	$ 180,346	A46	$ 180,346	A46	62
63	**Amortization of Deferrals**								63
64	New Source Review Litigation Costs	$ 985,111	A47	$ 985,111	$ 985,111	A47	$ 985,111	A47	64
65	MISO Day 1 Costs	$ 1,501,694	A48	$ 1,198,460	$ 1,501,694	A48	$ 1,501,694	A48	65
66	Rate Case Expense	$ 377,333	A49	$ 377,333	$ 377,333	A49	$ 377,333	A49	66
67	**Other Costs/Adjustments**								67
68	Property and Risk Insurance	$ 965,406	A50	$ 301,900	$ 301,900	A50-R	$ 301,900	A50	68
69	Claims Expenses	$ (678,893)	A51	$ (923,893)	$ (720,560)	A51-R	$ (833,893)	A51-S	69
70	Other Cost Reductions	$ (99,680)	A52	$ (99,680)	$ (99,680)	A52	$ (99,680)	A52	70
71	Changes in Cost Allocations	$ 21,588	A53	$ (32,771)	$ (32,771)	A53-R	$ (32,771)	A53	71
72	Asset Management Program Costs	$ 103,480	A54	$ 103,480	$ 103,480	A54	$ 103,480	A54	72
73	Asset Management Program Savings	$ (35,923)	A55	$ (35,923)	$ (35,923)	A55	$ (35,923)	A55	73
74	Customer Service Costs	$ -	A72	$ -	$ 93,000	A72-R	$ 93,000	A72	74
75	Going Level Uncollectible Accounts								75
76	IURC Fee	$ 73,681	A56	$ 73,681	$ 73,681	A56	$ 73,681	A56	76
77		33,166,830		$ 22,938,990	27,421,909	-	26,130,964		77
78	Asset Charge	$ 935,996	A57	$ 196,096	$ 869,756	A57	$ 521,368	A57-S	78
79	Total Operations and Maintenance	$ 34,102,826		$ 23,135,086	$ 28,291,665		$ 26,652,332		79
80	Depreciation and Amortization	$ 161,266	A58	$ (2,377,679)	$ (59,234)	A58-R	$ (59,234)	A58	80
81		$ 5,545,114	A59	$ 5,545,114	$ 5,545,114	A59	$ 5,545,114	A59	81
82	Total Depreciation and Amortization	$ 5,706,380		$ 3,167,435	$ 5,485,880		$ 5,485,880		82
	Taxes								
83	Income Taxes (Federal and State)	(6,340,013)	A60	$ (4,836,625)	$ (5,480,735)	A60	$ (5,341,392)	A60	83
84		175	A61	$ 96,032	$ 175	A61	$ 175	A61	84
85		(23,872,803)	A62	$ (18,210,995)	$ (20,636,763)	A62	$ (20,112,777)	A62	85
86	Other Taxes (IURT and Property Tax)	614,744	A63	$ 621,677	$ 618,788	A63	$ 621,677	A63	86
87		933,537	A64	$ 933,502	$ 933,537	A64	$ 933,537	A64	87
88	Total Taxes	(28,664,361)		(21,396,410)	(24,564,999)		(23,898,781)		88
89	Total Operating Expenses	11,144,845		4,906,111	9,212,546		8,239,431		89
90	Total of All Pro Forma Adjustments (Line 26 - Line 89)	(43,334,946)		(32,326,999)	(36,699,552)		(35,726,437)		90

VECTREN
Energy Delivery

Vectren Proposal for Reliability Reporting to the OUCC

Recommended Reporting Logistics:

Vectren and the OUCC have worked collaboratively to identify a format and procedures for reliability reports and meetings to assure the reliability programs described in the present Vectren rate case are developed, focused, and implemented to benefit our rate payers. We expect to continue to do so to finalize the actual report content, the timing of and agenda for the regular meetings, and any reasonable modifications brought on by changes in business needs, available technology, reliability program evolution or other issues mutually agreed upon. Initial suggested reporting and meeting criteria are provided below.

- Vectren will provide written reports to the OUCC twice a year, for a period of 3 years.
- Face to face meetings will be held at least once a year.
- Proposed reporting content and format is subject to review and modification after rate case settlement to assure that all appropriate programs are included (as they may be slightly different than those initially proposed and included here).
- Report content and format will be dynamic and evolve through discussions between the OUCC and Vectren.

VECTREN
Energy Delivery

Annual Reliability Based Maintenance Plan Report

This report (in the fall of the year) will include a high level summary of the programs and the areas planned for focus in the coming year. This proposal is the result of collaborative discussions with the OUCC. Vectren will share results of pertinent engineering and reliability studies including those identified in testimony and to be completed in future. In addition, Vectren will provide technological improvement updates, including the Asset Management Transformation (AMT) project. Any significant effects on operations, staffing, and procedures due to technological improvements will be identified.

- Major programs would be summarized such as:
  - Overhead Reliability Program
    - Include the list of circuits planned for inspection and remediation in the coming year.
  - Pole Inspection Program
    - Summary of plan for inspection for the coming year – may be by circuit, substation, map grid, etc.
  - Distribution Line Clearance Program
    - Areas targeted for tree trim in the coming year - may be by circuit, substation, main lines vs. laterals, map grid, etc.
  - Pole Guy/Grounding Program
    - Summary of plan for inspection for the coming year – may be by circuit, substation, map grid, etc.
  - Underground Pad Mount Equipment Inspection Program
    - Summary of plan for inspection for the coming year – may be by circuit, substation, map grid, etc.
  - Underground Downtown Network Reliability Program
    - Summary of plan for inspection for the coming year – may be by circuit, map grid, city block, etc.

- Some programs will be discussed in lesser detail (but included because of significant expense):
  - Substation Painting Program
  - Transmission Tower Painting Program

- The remaining programs will be combined for reporting purposes and may include the following:
  - Distribution Infrared Inspections
  - Transmission Infrared Inspections
  - Substation Infrared Inspections
  - Pole Attachments
  - AEGIS Recommendations
  - SCADA Inspection
  - Flyover Inspections
  - Newly identified programs
  - Modified or discontinued programs

VECTREN
Energy Delivery

Annual Report of Previous Year's Results

This report (in the spring) will review the previous year's results and identify any modifications or enhancements in the current year programs that have occurred since the previous reports were prepared. This report will be part of the annual meeting between Vectren and the OUCC.

- Progress on programs will include information such as:
- Reliability Indices, as reported to the IURC annually, with more granular detail and a review of values with and without major events
- Demonstration of progress (may include a more detailed breakdown of indices by outage cause and/or maps showing the areas where programs have focused.)
- Identify known or expected deviations from the plan previously provided.
- General observations
- Lessons learned and how those lessons m ay be applied.
- Trends identified and resulting activities.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing Stipulation and Settlement Agreement was served by depositing a copy thereof in the United States mail, first class postage prepaid, addressed to:

OFFICE OF THE UTILITY CONSUMER COUNSELOR
100 North Senate Avenue
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Indianapolis, Indiana 46204

J. Christopher Janak
Christopher C. Earle
L. Parvin Price
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BOSE MCKINNEY & EVANS
2700 First Indiana Plaza
135 North Pennsylvania Street
Indianapolis, IN 46204

Timothy L. Stewart
Jennifer W. Terry
LEWIS & KAPPES, P.C.
One American Square
Suite 2500
Indianapolis, IN 46282

this 20th day of April, 2007.

Daniel W. McGill
Daniel W. McGill

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Vectren South Electric
WPM Results Included in NOI Earnings Test -- *Company Share of Excess WPM Excluded from Actual NOI*
Example -- For Illustration Only

Objective: Include WPM results in the statutory NOI test while retaining some incentive opportunity

Assumptions ($ in Millions):

1	Authorized NOI	$	76.4
2	WPM included in Base Rates	$	10.5
3	Customer Sharing 50/50		

This apprroach assumes WPM portion is excluded from Actual NOI .

	A	B	C	D	E	F		G	H	I	J	K	L
	Examples:	Actual WPM	WPM in Base Rates	Net, Subject to Sharing	Company Incremental Share of WPM Opportunity	Company Incremental Share of WPM Opportunity, After Tax (NOI)		Actual NOI	Excess Attributable to WPM	Adjusted Actual NOI	Authorized NOI	Excess Earnings (I-J)	Impact on Earnings Bank Over/(Under)
4	1	$ 15.5	$ 10.5	$ 5.0	$ 2.5	$ 1.5	A	$ 76.4	N/A	$ 76.4	$ 76.4	$ -	-
5	2	$ 15.5	$ 10.5	$ 5.0	$ 2.5	$ 1.5	B	$ 78.4	$ 1.5	$ 76.9	$ 76.4	$ 0.5	$ 0.5

6	A	$	74.9	NOI from operations-before Company share of WPM
7			1.5	NOI from Company sharing of WPM over base rate amount
8		$	76.4	Book NOI
9	B	$	76.9	NOI from operations-before Company share of WPM
10			1.5	NOI from Company sharing of WPM over base rate amount
11		$	78.4	Book NOI

Practical Approach:

12 **Step 1 -- If Actual book NOI is less than Authorized, no action necessary and earnings bank reflects under earnings**

13 **Step 2a -- If Actual book NOI over Authorized, determine whether company's share of WPM results contributed to the NOI excess earnings; and**

14 **Step 2b -- If WPM is over $10.5 m base rate level, company share of that amount over $10.5m up to $3 million is excluded from actual NOI and compared to authorized**

COPY

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. ("VECTREN SOUTH – ELECTRIC") FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES APPLICABLE THERETO; (3) INCLUSION IN ITS BASE RATES OF COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY PROJECTS; (4) AUTHORITY TO IMPLEMENT A RATE ADJUSTMENT MECHANISM TO TRACK INCREMENTAL CHANGES IN CERTAIN COSTS AND REVENUES RELATING TO ITS GENERATING FACILITIES; (5) AUTHORITY TO IMPLEMENT A RATE ADJUSTMENT MECHANISM TO TRACK INCREMENTAL CHANGES IN NON-FUEL RELATED MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC. ("MISO") CHARGES AND PETITIONER'S TRANSMISSION REVENUE REQUIREMENT; (6) APPROVAL AS AN ALTERNATIVE REGULATORY PLAN PURSUANT TO IND. CODE § 8-1-2.5-6 OF A RETURN ON EQUITY TEST TO BE USED IN LIEU OF THE STATUTORY NET OPERATING INCOME TEST IN ITS FUEL ADJUSTMENT CHARGE PROCEEDINGS; (7) APPROVAL OF REVISED DEPRECIATION ACCRUAL RATES; (8) APPROVAL OF THE CLASSIFICATION OF PETITIONER'S FACILITIES AS TRANSMISSION OR DISTRIBUTION IN ACCORDANCE WITH THE FEDERAL ENERGY REGULATORY COMMISSION'S SEVEN FACTOR TEST; AND (9) APPROVAL OF VARIOUS CHANGES TO ITS TARIFF FOR ELECTRIC SERVICE INCLUDING NEW INTERRUPTIBLE AND ECONOMIC DEVELOPMENT RIDERS	)	FILED MAY 01 2007 INDIANA UTILITY REGULATORY COMMISSION **CAUSE NO. 43111**

AMENDMENT TO
STIPULATION AND SETTLEMENT AGREEMENT

The Indiana Office of Utility Consumer Counselor, Intervenor Industrial Group and Vectren Energy Delivery of Indiana, Inc., a/k/a Southern Indiana Gas and Electric Company, Inc. hereby agree to amend the Stipulation and Settlement Agreement filed with the Commission in this Cause on April 20, 2007, to make the following corrections:

1. On page 3, line 4, change $60,798,647 to $60,794,647.

2. On page 4 in the fifth line in the paragraph labeled Authorized Return, delete "gas cost adjustment (Ind. Code §§ 8-1-2-42(g)(3)(C) and -42.3)" and substitute "fuel adjustment charge (Ind. Code §§ 8-1-2-42(d)(3) and -42.3)."

ACCEPTED and AGREED this 1st **day of May, 2007.**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

By: ______________________
Jeffrey M. Reed
Assistant Consumer Counselor

VECTREN ENERGY DELIVERY OF INDIANA, INC. a/k/a SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

By: Robert E. Heidorn DWM
Robert E. Heidorn

INTERVENOR INDUSTRIAL GROUP

By: ______________________
Timothy L. Stewart

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing Amendment to Stipulation and Settlement Agreement was served by depositing copies thereof in the United States mail, first class postage prepaid, addressed to:

OFFICE OF THE UTILITY CONSUMER COUNSELOR
100 North Senate Avenue
Room N501
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LEWIS & KAPPES, P.C.
One American Square
Suite 2500
Indianapolis, IN 46282

this 1st day of May, 2007.

Daniel W. McGill

Daniel W. McGill

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